EXPRIMENTAL ANALYSIS OF SANDSTONE FORMATION DAMAGE WITH DRILLING FLUID INTRUSION IN VERTICAL AND HORIZONTAL WELLS

DEPARTMENT OF PETROLEUM & GAS ENGINEERING

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Dedication

This project is dedicated to Our Teacher Engr. Abdul Wakeel. His guidance and inspiration have shaped us, and his belief in our potential continues to drive us forward. Thank you for being an extraordinary educator, leaving an everlasting impact on our lives.

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We would like to express Our sincere gratitude and appreciation to all those who have contributed to the successful completion of this project.

Almighty Allah

Who gave us the strength in fulfilment of thesis

Our Supervisor

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DECLARATION OF THE AUTHOR

It is hereby declared by **Kamran Saeed**, **Wasif Rahim, Mohammad Younas, and Saad Satakzai** that the topic of our BS project/thesis: **"EXPRIMENTAL ANALYSIS SANDSTONE FORMATION DAMAGE WITH DRILLING FLUID INTRUSION IN VERTICAL AND HORIZONTAL WELLS"** is our own spectacular work, and it has not been presented for a degree from Balochistan University of Information Technology, Engineering & Management Sciences, Quetta, or elsewhere in the country. Even if this claim is found to be false at any moment after my graduation, the university does have right to rescind my BS degree.

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We hereby certify absolutely that the research presented in the thesis named "**EXPRIMENTAL ANALYSIS SANDSTONE FORMATION DAMAGE WITH DRILLING FLUID INTRUSION IN VERTICAL AND HORIZONTAL WELLS"** is our own study project, with no key input from anyone. Small contributions/assists have been sincerely received, and our group members collectively written the entire thesis.

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CERTIFICATE OF APPROVAL

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ABSTRACT

Formation damage is a significant challenge encountered in petroleum reservoirs during various stages of reservoir development, including drilling and production. It results from factors such as particle invasion, fines migration, chemical precipitation, and pore deformation. The adverse impact of formation damage on well productivity is primarily attributed to reduced permeability near the wellbore. Therefore, comprehending the mechanisms underlying formation damage is crucial for predicting its extent, severity, and effective control.

This experimental study focuses on investigating the formation damage caused by drilling fluid invasion. The invasion of drilling fluid into the formation can lead to permanent permeability impairment in the wellbore. The extent of damage depends on variables such as contamination time, fluid type, and overbalance pressure. Formation damage can manifest as either temporary or permanent. The aim of this study is to analyze the effects of drilling fluid type, mud composition (particularly total dissolved solids), and contamination time on permeability impairment. Experimental investigations were conducted on sandstone core samples using water-based mud and varying contamination times.

The outcomes of this study contribute to recommendations for improving drilling fluid selection, optimizing drilling techniques, and understanding the reasons why horizontal wells are more susceptible to formation damage and permanent permeability loss. To mitigate formation damage and maximize production, it is crucial to minimize overbalance pressure and contamination time, thus operating within a safe window. Additionally, emphasis should be placed on designing mud systems with minimal solid particle content. These recommendations are pertinent to both vertical and horizontal wells, although they hold particular significance for horizontal wells, where the implications of effective formation damage prevention can be transformative.

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1. Introduction

1.1. Formation damage:

Formation damage is the term used to describe the impairment or decrease in an oil or gas reservoir's inherent productivity brought on by numerous variables during the drilling, completion, or production activities. It can result in decreased flow rates, decreased ultimate recovery, or even complete loss of productivity in extreme cases. Formation damage is a significant concern in the oil and gas industry because it can significantly impact the profitability and efficiency of a well or reservoir.

There are several types of formation damage that can occur:

- **Mechanical damage:**

This occurs due to physical processes such as excessive pressure, improper drilling techniques, or inadequate wellbore stability. It can lead to the collapse of formation rocks, formation compaction, or plugging of pore spaces, which reduces the permeability and porosity of the reservoir.

- **Chemical damage:**

Chemical reactions between the fluids used during drilling, completion, or production and the reservoir rock can cause damage. For example, incompatible fluids may react with the rock, leading to the precipitation of solid particles or the formation of scales that can block the flow paths.

- **Fluid invasion damage:**

When drilling or completion fluids invade the reservoir formation, they can cause damage by blocking or narrowing the pore spaces, reducing the effective permeability. This invasion can occur due to excessive pressure imbalances or inadequate drilling or completion practices.

- **Fines migration:**

Fine particles present in the reservoir can migrate and accumulate near the wellbore, causing plugging and reducing the permeability of the formation. This migration is often driven by changes in pressure or fluid properties.

- **Organic damage:**

In some cases, organic materials present in the reservoir, such as waxes, Asphaltenes, or paraffins, can deposit and accumulate in the near-wellbore area, restricting the flow of hydrocarbons and reducing productivity.

To minimize or mitigate formation damage, various techniques and practices can be employed. These include selecting compatible drilling and completion fluids, optimizing drilling and production parameters, using appropriate wellbore clean-up methods, employing effective stimulation treatments, and implementing well-designed reservoir management strategies.

Reservoir engineers and production specialists rely on laboratory experiments, well testing, and simulation models to accurately assess and address formation damage. By understanding the mechanisms and extent of damage, they can design appropriate remediation or prevention measures [11].

1.2. Porosity: -

The porosity governs the storage capacity of rock or, in other words, the oil and gas contained in unit volume of rock.

Porosity (φ) is the ratio of the total void space within a rock (the pore volume) to the total bulk volume of that rock i.e.

$$porosity = \varphi = (V_p / V_b) \times 100, (percent)$$

Where:

V_p = Pore Volume

V_b = Bulk Volume

The volume of a rock that can hold reservoir fluids is known as its porosity. As a result, porosity has a direct impact on the amount of oil, gas, and water in a particular reservoir.

Or

Due to their irregular shapes, the sand grains and carbonate particles found in sandstone and limestone reservoirs do not fit together perfectly. As a result, fluids such as liquids and gases occupy the gaps or pore spaces between these grains, forming an interconnected void network within the reservoir. The porosity of the reservoir refers to the proportion of the total volume that is not occupied by the solid framework. Mathematically, it can be represented as:

$$\varphi = \frac{Vb - Vgr}{Vb} = \frac{Vp}{Vb}$$

where

φ = porosity, fraction

V_b = bulk volume of the reservoir rock

V_{gr} = grain volume

V_p = pore volume

As per the given definition, porous materials can possess varying porosity values. However, it is typically observed that the porosity of sedimentary rocks is commonly less than 50 percent [8].

- **Types of porosity**

There are different types of porosity:

- **Primary porosity:**

  Initially formed during deposition and is primarily reliant on the depositional environment. It is determined by factors such as sorting, grain size, matrix cementation, and grain shape.

- **Secondary porosity:**

  Formed during the diagenesis of rocks. Usually as a result of rock grains dissolving to create voids or vugs.

- **Absolute porosity:**

  The division of the total pore space in a rock by its bulk volume gives rise to what is referred to as absolute porosity. It is worth noting that a rock can possess significant absolute porosity but still lack fluid conductivity due to a lack of interconnected pores. The following mathematical expressions are commonly used to denote absolute porosity:

  φ_a= (total pore volume - bulk volume)

  or

  φ_a= (bulk volume-grain volume) / bulk volume

  where

  φ_a = absolute porosity

- **Effective porosity:**

  The effective porosity refers to the proportion of interconnected pore space in relation to the bulk volume, expressed as a percentage. It can be represented as:

  φ_e= (interconnected pore volume) / bulk volume

  Where

  φ_e = Effective porosity

The effective porosity represents the interconnected pore space that contains recoverable hydrocarbon fluids, and it is this value that is utilized in all reservoir engineering calculations.

Various methods are available to measure porosity:

1. Direct measurement from cores.
2. Well logs; sonic, density, neutron, NMR.

In order to determine the porosity of a core, it is essential to measure any two of the following parameters: bulk volume, pore volume, and grain or rock volume.

Rocks are heterogeneous, resulting in variations in porosity throughout the reservoir in both the vertical and horizontal directions [1].

- **Factors Governing the Magnitude of Porosity:**

Fraser and Graton conducted a study to examine the porosity of various arrangements of uniform spheres, aiming to determine the general limits of porosity. They found that the wide-packed system, also known as the cubic packing, exhibited a porosity of 47.6 percent, while the close-packed system, known as the rhombohedral packing, had a porosity of 25.9 percent. Notably, the porosity remained consistent regardless of the grain size (sphere diameter) within these systems. However, the introduction of smaller spheres alongside the existing ones in either system resulted in a decrease in porosity, leading to a lower ratio of pore space to the solid framework. For instance, in a cubic packing with three different grain sizes, the current porosity measures approximately 26.5 percent.

Petroleum reservoir porosities range from 5% to 40%, but are typically between 10% and 20%. The following factors affect how porous clastic deposits are:

(a) **Uniformity of grain size**: Uniformity or sorting is the gradation of grains. If small particles of silt or clay are combined with larger sand grains, the effective (intercommunicating) porosity can be notably lessen. The time period "dirty" or "shaly" is used to explain those reservoirs. Sorting is stimulated through at least four major variables: the scale distribution of the material, the form of deposition, the traits of the existing, and the time scale of the sedimentary system.

(b) **Degree of cementation or consolidation:** The soft, unconsolidated rocks have high porosities in contrast to the highly cemented sandstones. By moving groundwater, cementation occurs both during lithification and rock alteration. The procedure essentially entails filling spaces with mineral material to decrease porosity. Cementing ingredients also include limonite, hematite, dolomite calcium sulphate, iron oxide, calcium magnesium carbonate, iron carbonate, iron Sulphide, and clays and any combination of these.

- **Amount of compaction during and after deposition:**

In sedimentary rocks, especially those with finer grains, compaction plays a significant role in reducing voids and expelling fluids, leading to the consolidation of mineral particles. The primary mechanism by which petroleum migrates from its source to reservoir rocks is through fluid expulsion due to compaction at elevated temperatures. However, the impact of compaction on lithification varies among different rock types. While closely packed sandstones and conglomerates are significantly affected by compaction, claystone, shales, and fine-grained carbonate rocks experience minimal changes during the lithification process. Generally, porosity decreases with depth in older rocks, although there are exceptions to this trend. Notably, many carbonate rocks show limited signs of physical compaction.

- **Methods of packing:**

Poorly sorted angular sand grains exhibit a progressive transition from random packing to a closer packing with increasing overburden pressure. The sand particles are crushed and deformed in a plastic way [8].

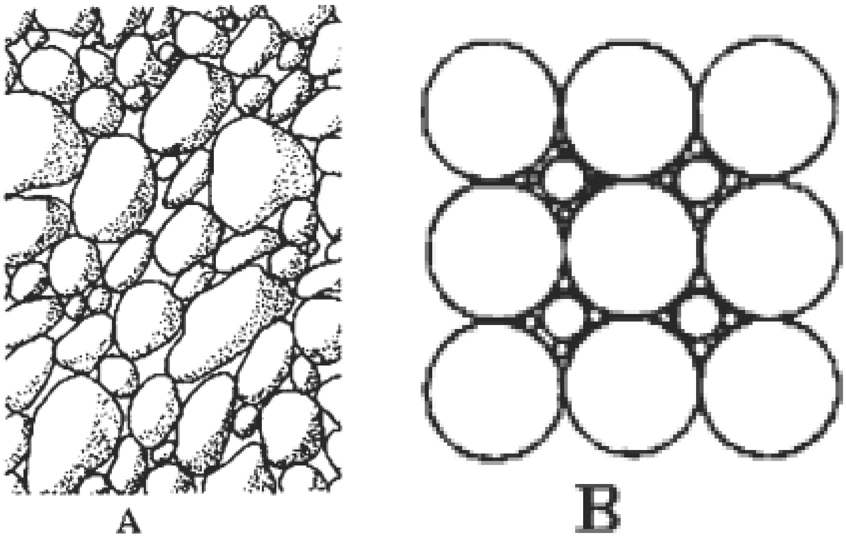


Figure 0-1. different sized and shaped sand grains and (b) spheres illustrating a cubic packing of three grain[8]

1.3. Permeability: -

Oil and gas production is significantly and directly impacted by the permeability, which is a measurement of the medium's capacity to transport fluids (oil, water, and gas) under a particular pressure differential.

The capacity and ability of the formation to transmit fluids are measured by the porous medium's permeability property. Because it regulates the flow rate and direction of the reservoir fluids within the formation, the rock's permeability, or k, is a crucial rock property. Henry Darcy developed the first mathematical definition of this rock characterization in 1856. In actuality, the equation that expresses permeability in terms of quantifiable values is known as Darcy's Law.

Darcy developed a fluid flow equation, which is now one of the basic mathematical tools employed by petroleum engineers. If a core sample of length L and a cross-section of area A are used to generate a horizontal linear flow of an incompressible fluid, the following equation is the one that governs fluid flow:

$$v = \frac{q}{A} = -\frac{k}{\mu}\frac{dP}{dL}$$

where

v = apparent fluid flowing velocity, cm/sec

k = proportionality constant, or permeability, Darcy’s.

μ = viscosity of the flowing fluid, cp

dP/dL = pressure drop per unit length, atm/cm [2].

- **Absolute Permeability**

  - The capability of a rock to flow in a specific way. The capacity of a porous substance to transport fluids.
  - The measurement of a chosen porous medium's fluid conductivity
  - The ability of a rock to transmit or flow through a single-phase fluid when it is entirely saturated with the substance.
  - The reciprocal of the resistance a porous media provides to fluid flow.
  - Stable proportionality between the applied pressure gradient and the fluid flow rate.

- **Effective Permeability:**

Absolute permeability is a measure of a rock's ability to carry just one fluid at a time. Effective permeability is the degree to which each phase can pass through the connected pore space. The resistance to fluid flow through a connected pore space tends to rise as a result of interfacial tension caused by the mixing of immiscible fluids. the total of the effective permeabilities for each phase hence "is less than the absolute permeability;" thus

$$\sum_{l=1}^{N} (\mathrm{kr})_{eff} \leq k_{abs}$$

where N is the number of present phases. Relative permeability definitions indicate the effective permeability of multi-phase flow.

➢ **Relative Permeability:**

we define relative permeability as the ratio of effective permeability to reference permeability; thus:

$$k_r = \frac{k_{eff}}{k_{ref}}$$

where

k_{eff} = effective permeability of fluid (md)

k_{ref} = reference permeability (md)

The absolute permeability of air serves as the standard reference permeability. The following frequently used effective permeabilities can be obtained if we identify the reference or base permeability as k:

$$\text{Oil:} \quad k_{ro} = \frac{k_o}{k}$$

$$\text{Water:} \quad k_{rw} = \frac{k_w}{k}$$

$$\text{Gas:} \quad k_{rg} = \frac{k_g}{k}$$

it may be seen from these definitions that relative permeability varies among 0 and 1 because k_eff ≤ k. The sum of the relative permeabilities over all phases l at the same time and place satisfies the inequality[9].

$$\sum_{l=1}^{N} (\mathrm{kr})_{rl} \leq 1$$

1.4. Formation Damage:

A Portion of the drilling mud liquid, known as the mud filtrate, is forced into any permeable rock nearby the wellbore when drilling a well with overbalance. The mud filtrate can cause formation damage or skin damage to reservoir rocks nearby the wellbore by reducing or destroying their permeability. Acidizing (wash job) or hydraulic fracturing are two well stimulation techniques that can be used to repair formation damage in a well.

Formation damage can be prevented while drilling through the lost-circulation zone by circulating brine (extremely salt water), an oil-based emulsion, or synthetic drilling mud. Using a light-weight drilling mud that exerts less pressure than the formation pressure (underbalance drilling) is another way to avoid it. Drilling that is unevenly balanced will hasten the well's completion but won't prohibit fluids from seeping into the well from the rocks. On the rotary table, a revolving control head is employed to keep pressure under control when drilling with an unbalanced load. A still outer housing encloses the Kelly and includes a rotating inner seal assembly. Any returns coming up the well from the rig floor are intended to be diverted by the rotating control head. Underbalanced drilling typically only occurs during a small portion of the overall drilling process. Before tripping out when drilling with underbalance, the well must be killed by filling with heavier drilling mud [3].

1.4.1. Formation Damage Mechanisms:

1. Mechanically Induced Formation Damage.
2. Chemically Induced Formation Damage.
3. Biologically Induced Formation Damage.

- **Mechanically Induced Formation Damage:**

- **Fines Migrations:**

  The movement of the fines or silica particles from initial position inside the pore area by using drag forces (function of speed of drift) when turn out to be greater than binding forces. however, in a few situations, fines migration can also arise in carbonates by using the migration of crystalline dolomite, limestone fines.

  The connection between fines migration and Wettability must be emphasized at this point. Generally speaking, particles travel almost exclusively within the phase, wetting the rock. For instance, if the deposit is water-wet, gas or oil might be generated through it at incredibly high rates without there being a significant physical tendency for fines migrations since the fines are contained within the still and unmoving connate water section.

When the wetting phase saturation reaches a sufficient level (via water breakthrough, water conning, invasion of water base drilling, finishing touch or stimulation fluid into the formation, and subsequent drawdown of the formation to generate it), fines migration may occur most effectively.

The tendency for particles migration exists immediately at perforation when the wetting oil segment starts off developed to flow if the formation is oil wet. Additionally, in some cases, the intensity of fines mobilization can be significantly increased by turbulence caused by simultaneous multiphase flows of both the wetting and non-wetting phases. The pore opening may be intentionally blocked by fines migrations, which will reduce permeability.

- **Solids Invasion:**

Solids present in drilling and nicely completion fluids encompass one or greater of the subsequent:

- Drilling solids (cutting).
- Weighting materials (barite).
- Viscosities (bentonite).
- Fluid loss additives (calcium carbonate).
- Loss circulation materials (of varying size and composition).
- Solid precipitation (salts, scales).
- Microorganism.
- Perforation particles.

The degree and depth of solids invasion is ruled by:

- Formation pore throat size and distribution.
- Particle size distribution of mud solids.
- quantity of pressure overbalance (elevated overbalance or surge pressures yield increased invasion).

- **Water Block: -**

Water invasion into low permeability rock will be assisted by the strong capillary forces associated with the small pore throat dimensions. This phenomenon is called water block. It occurs most frequently during hydraulic fracturing of poor quality rocks and in low pressure reservoir. Water blocking decreases the absolute permeability (K).

- **Chemically Induced Formation Damage: -**

Chemically Induced Formation Damage can be divide into three major categories:

- **Rock – Fluid incompatibilities:**

  a. Clay Swelling:

  When water from drilling and completion fluid comes in touch with clay, it may swell. Clay can considerably lose permeability in absolute terms when it swells.

  b. Clay deflocculation:

  A clay mineral is in a flocculated state when its constituent particles tend to group together into flocks or lumps, and it is in a deflocculated state when these flocks or lumps are broken up or separated. Particles that have been dispersed may block pore throats, reducing permeability.

  c. Formation Dissolution:

  When drilling fluid has a water base, potential issues with formation de-solution may arise. Unstable hydratable shale, clay-rich zones, halite zones, and anhydrite zones are examples of potentially reactive zones. Physical issues, including wellbore collapse, can arise from physical breakdown.

  d. Chemical adsorption:

  Most drilling fluids incorporate different chemical additives to enhance their performance. When these compounds have a large molecular size, their physical adsorption can block a considerable portion of the available pore space, leading to reduced permeability and hindered flow.

- **Fluid-Fluid incompatibilities:**

  a. Organic scaling

  Organic scaling of aspartames and waxes is caused by:

  - Changes in pressure and temperature.
  - Contact with certain light hydrocarbon liquid.

  Asphalting will flocculate in crude oil and subsequently precipitate if contacted with high and/or low PH (water based) drilling and completion fluids, or (oil based) fluids containing diesel and other light hydrocarbons. Waxes precipitate if the temperature drops below their crystallization point.

Scaling results in a reduction absolute permeability and hydrocarbon mobility.

b. Inorganic scaling

Most formation waters contain bicarbonate and carbonate ions, initially at in-situ reservoir conditions (particularly for reservoir systems rich in CO_2 gas). Extraneous fluids containing $Ca2^+$ ions that contact bicarbonate rich water will cause calcium carbonate scale to form.

A decrease in pressure, either during production or across perforations, will cause a subsequent decrease in CO_2 partial pressure also leading to calcium carbonate scale formation. In reservoirs containing saturated formation brine, pressure differences change the solubility of inorganic salts causing precipitation in the near wellbore region.

- **Wettability alterations caused by invading fluids:**

In order to improve the performance and properties of drilling fluids, a wide range of chemical additives, including surface active additives, are commonly used. However, some of these additives have a tendency to undergo physical adsorption on the walls of pore throats. This adsorbed layer, resulting from surfactant adsorption, leads to a decrease in the effective pore throat size, which in turn causes various undesired effects such as reduced permeability and alterations in wettability.

- **Biologically Induced Formation Damage:**

Naturally Occurring Formation Damage is a mechanism that is frequently ignored. Reductions in permeability frequently take a while to manifest instead than occurring suddenly. When a variety of bacterial agents are introduced, proliferate, and spread inside the porous media, it might result from a number of different operative methods. In general, there are two groups of bacteria that are active in porous media:

- Anaerobic bacteria and aerobic bacteria. Aerobic bacteria need a constant supply of dissolved oxygen to survive and spread within the rock.
- Anaerobic bacteria, which do not require a continuous source of dissolved oxygen.

1.4.2. Quantification of Formation damage:

Skin factor refers to the area surrounding a wellbore where permeability is either reduced or enhanced. This phenomenon is typically attributed to formation damage, invasion of mud filtrate during drilling or perforating, or well stimulation. In the flow equation, which assumes isotropic and homogeneous porous media, the skin factor is employed to account for non-ideal conditions and adjust the equation accordingly. It incorporates various characteristics that were not originally considered in the theoretical derivation of the flow equation.

Accurate determination of the skin factor is obtained through well test analysis, but its interpretation varies depending on the type of flow regime. While it is not possible to completely eliminate the skin factor, it can be minimized or reduced by modifying operational procedures and optimizing relevant parameters. Implementing such practices in specific sections or targeted zones of interest can optimize production rates and contribute to improved recovery factors. By prioritizing production optimization operations and striving for minimal skin factor, the overall efficiency of reservoir operations can be enhanced [28].

By gaining a better understanding of drilling parameters and optimizing completion procedures, the adverse effects on the wellbore zone can be significantly minimized [28]. Positive skin values indicate the presence of damage or factors that impede well productivity. This positive skin leads to increased pressure drop, resulting in reduced well productivity and decreased revenue. Additionally, positive skin causes a reduction in the effective wellbore radius. On the other hand, negative skin values indicate improved productivity, often achieved through stimulation techniques. Negative skin values correspond to an increase in the effective wellbore radius.

Formation damage induced by drilling and completion fluids is commonly attributed to the apparent skin effect, known as the skin factor, in both vertical and horizontal wells. A higher skin factor indicates greater formation damage caused by these fluids. Various types of skin can be identified, including total skin, which encompasses damage, slanting, perforation, completion, and pseudo skin [28]. In this study, our focus is specifically on skin due to damage.

When drilling or completing a well, if the invasion of drilling or completion fluid occurs in the near wellbore region with an original permeability of k, resulting in an altered permeability of Ks within a radius of rs in a wellbore with a radius of rw, the skin due to damage can be quantified using Hawkins' formula, as stated in **Equation 1.1**.

$$\text{Skin due to damage} = \left(\frac{k}{ks} - 1\right) \ln \frac{rs}{rw} \quad \ldots\ldots\ldots\ldots\ldots\ldots.. (1.1)$$

Extra pressure drop near the wellbore region is caused by such skin. This extra pressure drop can be calculated by **Equation 1.2**

$$(\triangle\, p)skin = 141.2 \frac{q_o u_o B_o}{kh} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots. (1.2)$$

Drop of extra pressure renders the well performance passive.

1.5. Sandstone:

The main component of sandstone is sand that has been naturally cemented together. When touched, sandstone is gritty and feels like sandpaper. If they are only loosely cemented, the sand grains can be broken off the rock. The color of the rock ranges from white to buff to dark. Sandstones are frequently deposited on beaches, river channels, or dunes. It is the most significant oil reservoir rock in the United States and a typical reservoir rock for both gas and oil [3]

Sandstones consist of five primary components: cement, matrix, quartz, feldspar, and rock fragments known as lithic grains. The matrix is primarily composed of quartz particles with a silt-grade and clay minerals, and it is typically deposited alongside the sand particles. However, it can also form as a result of the diagenetic breakdown of unstable grains, with clay minerals precipitating in the diagenesis pores. During diagenesis, cementing agents such as quartz and calcite also precipitate around and between the grains. Diagenetic hematite can produce a reddish stain in sandstone.

The geology and climate of a region's source region are mostly reflected in sandstone's composition. Different grains and minerals have higher mechanical and chemical stability than others. In decreasing order of stability, the minerals quartz, muscovite, microcline, orthoclase, plagioclase, hornblende, biotite, pyroxene, and olivine are included. Immature sandstones contain a lot of unstable grains (rock fragments, feldspar, and mafic minerals), which is why the idea of compositional maturity is useful. Mature sandstones contain predominantly quartz, a tiny amount of feldspar, and small rock fragments, in contrast to super mature sandstones, which are virtually totally quartz. Super mature sandstones are the product of long-distance transit and substantial reworking, whereas compositionally immature sandstones are often deposited near to the source location. Thus, a sandstone's mineral composition is influenced by the geology of the source region, the level of weathering there, and the distance traveled.

Based on the ratios of quartz (chart), feldspar, rock fragments, and matrix in the rock, sandstones are generally categorized. Hybrid sandstones are referred to as sandstones having an extra, non-detrital component, such as carbonate grains, and are covered in the sections that follow. To establish a sandstone's composition, a modal analysis is carried out on a thin slice of rock using a point counter and a petrological microscope [6].

1.5.1. Horizontal Well:

A horizontal well is a deviated well that is drilled parallel to the reservoir to the pay zone (target). A tangent section separates the two build angle sections. Where the well first enters the target is known as the entry point. Latitudinally or horizontally, the well's portion that is horizontally oriented is known as this. The heel begins the lateral and the toe finishes it.

To maximize ultimate recovery from the reservoir, horizontal wells are also utilized in low-permeability (tight) formations. They are also employed to stop coning, which is the excessive production of gas or water from the oil reservoir's top or bottom. Although drilling a horizontal drain hole is not significantly more expensive than drilling a vertical well of comparable depth, it takes longer to log and complete. Any horizontal branch that is drilled out from the wellbore, the original vertical well, is referred to as a lateral. One well can support multiple laterals.

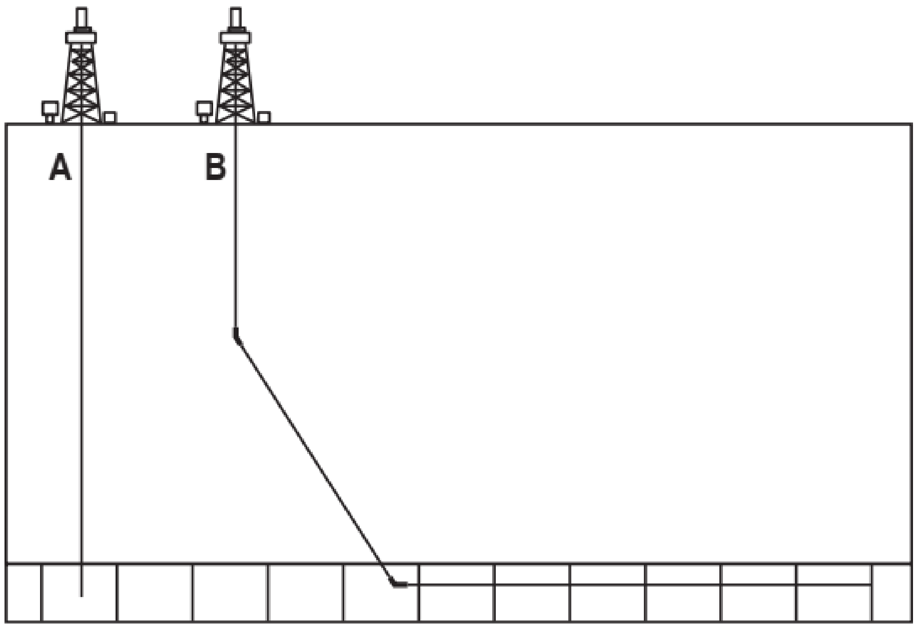


Figure 0-2 Vertical and Horizontal well terminology [3]

A reservoir well with a pay zone that is parallel to the well's highly deviated lateral (70° to 110°). The well's reach, or the length of its horizontal section, and radius of curvature (short, medium, and long radius) are used to describe it. A rotary steerable motor or steerable downhole assembly is used to drill it. The well is frequently finished in an open-hole fashion or with a perforated liner [3].

Since 1980, a steadily growing portion of hydrocarbon production has been captured by horizontal wells. The benefits of horizontal wells over vertical wells are as follows:

- Each horizontal well can drain a significant portion of the reservoir;
- Production from thin pay zones is higher.
- Horizontal wells reduce problems with gas and water zoning.
- Horizontal wells can be utilized to lower near-wellbore velocities and turbulence in high permeability reservoirs where near-wellbore gas velocities are excessive in vertical wells.
- Long horizontal injection wells offer higher injectivity rates in secondary and enhanced oil recovery applications.
- The horizontal well's length can allow for contact with numerous fractures and significantly increase productivity.

When compared to vertical wells, the horizontal well's actual production mechanism and reservoir flow regimes are thought to be more complex, especially if the horizontal segment of the well is particularly long. The well may behave similarly to a well that has been badly fractured since there is some combination of both linear and radial flow.

1.5.2. Vertical Well:

A well that was nearly straight down and within the drilling contract's specified cone of specific degrees, with a maximum tolerance in degrees per 100 feet for any well section. (Directed hole) cf. crooked hole and well-deviated [3].

Drilling contracts can have a clause that the well being drilled will be a vertical well or straight hole (***Figure 0-3***). The well cannot exceed a maximum deviation in degrees per 100 ft. anywhere along the wellbore, and the well must fit entirely within a cone of specific degrees.

During the early 1900s, the introduction of rotary drilling rigs posed challenges when drilling wells vertically through hard rock formations, particularly limestone (see ***Figure 0-3***). If the subsurface rock layer has a dip greater than 45°, the drilling bit is likely to deviate downwards. Conversely, if the hard rock layer has a dip of less than 45°, the bit is more likely to deflect upwards. A crooked hole refers to a well that has been unintentionally drilled at an excessive angle. Crooked hole country refers to a region where rock layers are inclined, resulting in the formation of crooked holes. To mitigate deviation, a slick bottom hole assembly without stabilizers can be employed in an attempt to drill a straight hole [3].

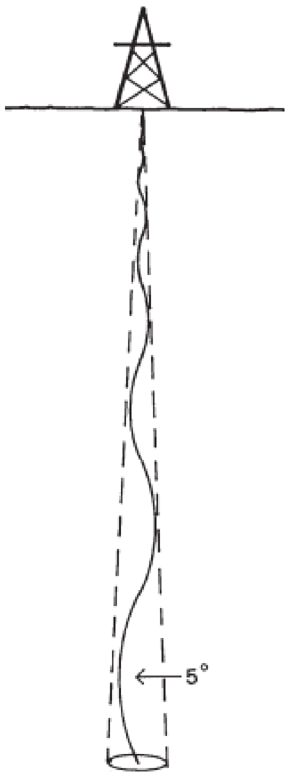


Figure 0-3. A straight hole [3]

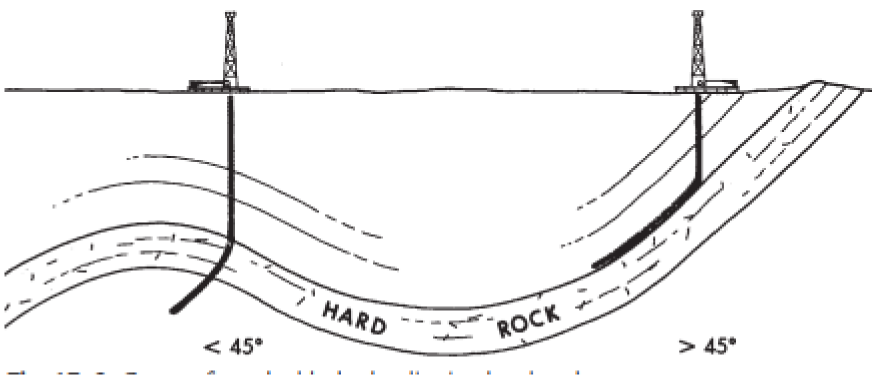


Figure 5. Cause of crooked holes by dipping hard rocks [3]

1.6. Drilling Fluid:

The drilling-fluid system, commonly known as the "mud system," maintains continuous contact with the wellbore throughout the drilling operation. These systems are meticulously engineered and formulated to operate effectively under normal wellbore conditions. With the advancements in drilling fluid technology, it is now possible to implement cost-effective and tailored systems for each phase of the well-construction process.

The active drilling fluid system is comprised of a specific volume of fluid that is circulated using specialized mud pumps. This fluid circulates from surface pits, through the drill string, and exits at the drill bit. It then travels up the annular space within the wellbore and is eventually returned to the surface for solids removal and necessary treatments. The capacity of the surface system is primarily determined by the rig size, which is selected based on the well design. For instance, in Deepwater wells, the active drilling fluid volume can be substantial, often reaching several thousand barrels. A significant portion of this volume is required to fill the extensive drilling riser that connects the rig floor to the ocean floor. On the other hand, a shallow well on land may only necessitate a few hundred barrels of fluid to achieve its intended objectives.

A properly designed and maintained drilling fluid performs several essential functions during well construction:

- Cleans the hole by removing drilling cuttings from the fluid before it is recirculated downhole at the surface.
- Balances or overcomes formation pressures in the wellbore to reduce the possibility of well control problems.
- Supports and stabilizes the wellbore walls until the equipment for open hole completion or setting and cementing casing can be installed.
- Minimizes or prevents damage to the producing formation(s).
- The drill string and bit are cooled and lubricated.
- Transmits hydraulic horsepower to the bit.
- Permits the analysis of cuttings, logging-while-drilling data, and wireline logs to provide information about the producing formation(s) [4].

1.6.1. Types of Drilling Fluid:

The two most common types of drilling fluids are water- and oil-based mud. Oil-based muds (OBM) are drilling fluids where oil is the continuous phase, while water-based muds (WBM) are drilling fluids where water (salt water or fresh water) is the continuous phase of the system. These muds will be discussed in detail in Sections 3 and 4 below. The most popular muds used worldwide are WBMs. Drilling fluids, however, can be broadly divided into two categories: liquids and gases. Compared to systems based on liquid, pure gas and gas-liquid mixes are utilized less frequently. Only areas with competent and impermeable formations (such as Virginia (West)) may employ air as a drilling fluid. High penetration rates, superior hole cleaning, and reduced formation damage are benefits of air-circulating system drilling. Air is unable to hold the borehole's sides or exert sufficient pressure to prevent formation fluids from entering the well. These are two significant drawbacks. When drilling in formations with pressures so low that even water causes significant losses, gas-liquid mixtures (foam) are most frequently used. This can happen in mature fields where low pore pressure has resulted from reservoir fluid depletion. Water based muds are relatively inexpensive because water, the fluid used to create them is easily accessible. Chemicals, liquids, and solids are all components of water-based muds. Clays are examples of active solids, which are solids that react with the chemicals and water in the mud. For the mud to work properly, the activity of these solids needs to be under control. Inactive or inert solids are defined as those substances in the mud that do not react (e. g. Barite). The drilling process produces the other inert solids. The majority of these muds are based on fresh water, but in offshore drilling operations, salt water is more easily accessible [5].

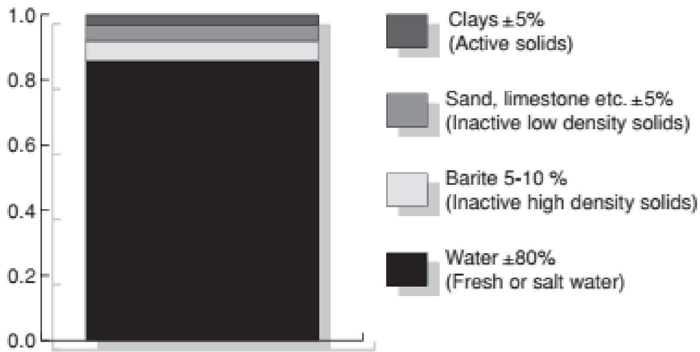


Figure 0-4 The typical makeup of a mud made of water is depicted [5]

Drilling fluids are typically classified based on their basic composition, which can be broadly categorized into liquids, gases, and liquid-gas mixtures. While natural gas or gas-liquid combinations were previously used, liquid-based formulations have become more common. Various categories of drilling mud are available, including compressed air, foam, clear water, water-based mud, oil-in-water emulsions, and oil-based mud. Additionally, specific components are often added to these fluids to address specific downhole challenges. For example, drilling mud can be freshwater or saltwater-based with the inclusion of additives. There are also specialized types of drilling fluids designed to meet specific requirements and possess distinct properties, which will be discussed separately below.

Drilling fluids commonly fulfill the key requirements of air and water, and specific chemical additives serve particular purposes. The selection of a drilling fluid is primarily influenced by several factors: 1) the type of formation to be drilled, 2) the available formation data encompassing stress, temperature, permeability, saturation, and power, 3) the chosen formation evaluation system, 4) the availability of water resources, whether fresh or saltwater, and 5) environmental considerations, including sustainability assessments. Nevertheless, determining the drilling fluid that yields the lowest drilling cost at a specific location often involves trial and error. The subsequent sections provide detailed descriptions of the distinctive drilling fluids [5].

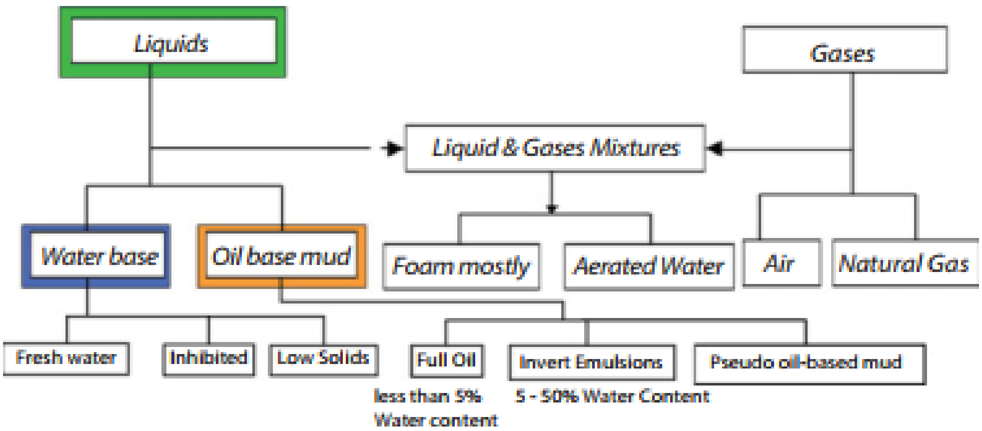


Figure 0-5. Classification of different drilling fluids [5].

➢ Water-based Mud

Water is the most commonly used liquid in drilling operations. When solids are mixed into the water, it forms a natural mud. Water-based mud (WBM) is a type of drilling mud where water serves as the continuous phase. While oil-based muds are prevalent in the North Sea, WBM is the most widely used drilling fluid globally. The advantages of WBM include: 1) effective hydration of clays in water, leading to increased mud viscosity and improved transport of rock cuttings to the surface; 2) formation of a mud cake by clay particles that prevents wall collapse and reduces water loss and unintended flow; and 3) lower mud cost compared to other mud types (around 10% of the total well cost). However, there are also risks associated with WBM, such as reduced penetration rate and increased frictional pressure losses, which may outweigh the benefits in small-diameter boreholes. To mitigate these risks and prevent the formation of natural clays, equipment for removing finely divided particles must be utilized. Freshwater and saltwater are the two types of water commonly used as the base for WBM formulations, with freshwater mud referring to a system where freshwater serves as the continuous liquid phase [17].

Brine water, seawater, dry sodium chloride or other salts, and potassium chloride are used to make saltwater drilling fluids. The chloride level of various fluids ranges from 6,000 mg/ft to less than 189,000 mg/ft. Attapulgite, p.c., CMC, and starch are commonly used materials to improve viscosity, as well as FCLS and caustic lignite to limit gel energy and filtrate loss. A mud that has been added calcium or salt to limit the hydration of active clays. An inhibited mud is one in which the water phase's reactivity with the active clays in the formation is significantly reduced. The main difference between freshwater and constrained muds is salt awareness. When a problem with drilling with fresh mud (sloughing clays) occurs, inhibited muds are utilized. Muds with fewer than 3000 ppm of Na+ ions are classified as freshwater muds. Shale and clay formations are currently drilled with it. Muds with low solids contents have a solid content of less than 5% [10].

- **Oil-based Mud**

Oil is used as the solvent in drilling mud (also known as "oil-based mud" or "OBM") to give the solids content. OBM is a drilling fluid with a continuous phase of oil and a water concentration of between 2% and 5%. Small droplets of this water are spreading out or distributed across the oil. Diesel, kerosene, and fuel oils are frequently utilized as base fluids. OBMs are used to expand programmers in situations where fluid balance and inhibition are required, such as in high-temperature (> 2000F), deep (> 16,000 ft) wells, salt- and unconsolidated-formation situations, and soft shale formations where sticking and hole stabilization are issues. OBMs are substantially more common in some areas because they result in less drilling challenges and far less formation damage than WBMs. When water-based muds negatively affect the formation and in unusually warm formations, OBM is frequently utilized. OBMs are typically used in horizontal and directional wells. Additionally, it is used to drill and core (i.e., collect samples for analysis) pay zones, problematic formations (such as shale), and to lessen corrosion [10].

1.7. Core Sampling:

Core sampling gives geologists a physical specimen rather than a downhole measurement, similar to what well checking out does for reservoir engineers. The advantage of introducing fluid and rock samples to the surface is that they can undergo tests and studies that are not possible inside the wellbore.

- **They are types of coring:** traditional coring, which uses drill strings, and wireline coring. In some development wells and exploration wells, traditional coring is frequently used. The lowermost part of the borehole is where core sampling takes place. A specialized coring bit is used to create a cylindrical opening in the rock formation. This core is then extracted and forced into the inner core barrel, which remains stationary while the outer core barrel, attached to the drill string, rotates during the drilling process. To prevent the core from escaping, a core catcher is employed at the surface. The size of the core can vary, but it is typically around 10 centimeters (4 inches) in diameter, while the core barrels themselves are usually nine meters (30 feet) in length. Special techniques have been developed to minimize the impact on the core during the drilling operation. These techniques aim to reduce mechanical movement to ensure optimal core preservation and minimize drill mud invasion to maintain the core's original fluid composition.

After the well has been drilled, wireline coring—also known as sidewall coring—is performed using a tool attached on a wireline cable. To position the coring device at the desired intensity, a correlation size with a gamma ray tool is employed. There are three different types of sidewall coring, although only one is frequently employed:

- Percussion Coring
- Core Reducing, And
- Sidewall Rotary Coring.

The core slicer, created, among others, by Schlumberger in the 1960s, was composed of motorized saw blades oriented at 60° to each other that were capable of cutting the borehole wall into four triangular pieces, each measuring one meter in length. This frequently disrupting configuration was dropped in favor of sidewall rotary coring in the 1990s.

After drilling and logging are finished, it is common practice to pattern zones that seem to be of interest using wireline coring. It is also frequently used to collect shale samples for biostratigraphy examination [7].

Chapter 2

2. Literature Review

Formation Damage basically consists of flow regulations due to a discount in permeability within the close to-wellbore area, changes in relative permeability to the hydrocarbon phase, and accidental flow restrictions inside the final touch itself. Formation damage estimated that billions of dollars in line with annum are misplaced via deferred production, remedial treatments and irrecoverable The primary issue that needs to be solved for effective and more profitable exploitation of hydrocarbon resources is formation damage. Any stage of a well's life cycle, including drilling, completion, production, and workover operations, may result in formation damage [11].

A vertical well's drainage pattern is very different from that of a horizontal well. In contrast to the vertical well, which has radial flow geometry in modern times, the flow geometry in a horizontal well is more likely to be linear far from the well and radial close to it. The significant influence of horizontal to vertical permeability anisotropy on horizontal correctly productiveness is every other crucial distinction between horizontal and vertical wells. Due to these factors, close-wellbore formation degradation affects horizontal wells differently than vertical wells, and it should be characterized using a unique skin element version [12].

2.1. Formation Damage in Vertical and Horizontal Wells:

The distribution of damage around a horizontal well is likely to be extremely non-uniform, which is a key contrast between vertical and horizontal wells. Depending on the ratio of the vertical to horizontal permeability, reservoir anisotropy may also result in a damage zone with an oval form perpendicular to the well. Due to the length of the formation that a horizontal well contacts, it is highly unlikely that formation damage will be distributed evenly down the well. Therefore, unlike the traditional assumption for vertical wells, the damage area surrounding a horizontal wellbore cannot be assumed to be a cylindrical region of lower permeability [13]. To assess the effectiveness of horizontal wells as a novel alternative to access and produce oil and gas reservoirs, many technical characteristics of horizontal wells have been compared with more conventional wells (vertical or deviated) [14].

Formation damage that occurs during horizontal or vertical well drilling may be a significant factor in oil and petrol bearing formations' continued lower productivity [15].

Hydraulic fracturing and matrix acidizing are the two most recent utility regions to compare horizontal and vertical wells and to conform procedures deployed to conventional wells to horizontal wells [14].

In comparison to vertical wells, the effect of close-by well formation damage on the completion of a horizontal well is rather minimal. However, if the thickness of the reservoir is great, radial flow becomes dominant and the impact of formation damage on a horizontal well is greater, comparable to that of a vertical well [12].

2.2. Drilling Fluid Formation Damages:

Drilling fluid intrusion into a fractured formation can cause severe formation damage across the wellbore, reduce well productivity, and delay field restoration. Testing representative field fluids and core samples under simulated down-hollow conditions, as is possible with dynamic formation damage, is a superb technique to evaluate damage potential [16]. Jiao et al. [17].

To decrease solids and invasion into a fragmented Berea core sample, it was defined how to use two particular bridging marketers, CaCO3 and acid soluble fibers. Their findings show that granular components made of CaCO3 are significantly less effective than fibrous additions. Without adding bridging agents to the drilling mud, drilling through a fractured reservoir will severely impair the fracture system's permeability. The permeability drop may not always be reversed during flow back when the crack is stuffed with drilling mud.

After drawdown, the drilling fluid itself does not necessarily cause more formation damage than the virgin reservoir residences [18].

The flow reduction within the reservoir can arise at some stage in drilling, completion or maybe workover operations. it is a zone of reduced permeability within the properly place of the wellbore due to foreign fluid or solid particles invasion into the reservoir rock [19].

Formation damage because of drilling fluids can arise by way of several unique mechanisms including, Mud solids invasion, formation fines dispersion, clay hydration, wettability change, etc. [20].

Water-based mud invasions and oil-based mud invasions may differ fundamentally. The displacement of oil in an oil-bearing formation using an oil-based mud filtrate is a miscible displacement technique, whereas the displacement using a water-based dust filtrate is a two-phase flow process (imbibition), resulting in excessive wetting phase saturations within the invaded zone [21].

2.2.1. Formation damage caused by Water Based Muds:

When mud circulates, particles create an inner and outside filter out cake, which causes harm to the formation. Mud filtrate may interact with formation particles, which may be incompatible with reservoir brine, and this interaction may be the cause. As a result, many reservoirs frequently see a significant decline in gas productivity. The deep gas well drilling process in the manufacturing zone is normally time-consuming, resulting in a much deeper filtrate invasion, making it impossible for formation damage caused by a drilling fluid to be formed.

Water Based Mud's dynamic filtrate loss is severely hampered by the annular speed and permeability of formation. Additionally, the particle range within the mud plays a crucial role in the effective depth of mud particle invasion. Formation damage to tight gas deposits is highly likely. In many of those circumstances, fluid retention is a major cause of injury. Knowing the reservoir's wettability and initial saturation levels is the first step in minimizing damage repercussions. Next, use extremely low fluid loss conventional systems or a well-managed Under Balance Drilling technology to reduce invasion [25].

Formation damage is typically attributable to resources at some stage during drilling, including filtrate invasion from a drilling fluid and the concomitant invasion and migration of solids. The potentially dangerous solids could arrive immediately from the fluid system or the formation itself. The rock loses some of its permeability as a result of the intrusion and deposition of these mobile particles, which plug pore throats. Regardless of the mud type used in fashionable, the damage occurs. However, the circumstances near the wellbore and the characteristics and content of the rock, mud filtrate, and solids that flow with it under dynamic settings determine how deep the damage is [25].

2.2.2. Formation damage caused by Oil-Based Muds:

Oil base mud prevents formation damage, however specially formulated water base low gravity mud can also effectively prevent formation damage due to economic, safety, and environmental considerations. It may be desirable to use low gravity water base drilling fluid.

When drilling in low pressure regimes, it is more lucrative to drill the target zone with low gravity mud and isolate the prior portion by a casing [22].

Oil-base muds are frequently used in zones where a water-base mud could not be drilled effectively or successfully, such as in problematic shale formations or deep, hot holes. Oil muds are also used in excessive-angle holes due to their low coefficient of friction. Since the continuous phase of these muds is oil, the filtrate lost is oil, which no longer serves as a sufficient incentive for the clays inside the formation to inflate. The oil muds also produce thin, impermeable filter cakes that lose the least amount of static fluid. However, additional chemicals are required to oil-wet the existing solids (barite and drilled cuttings) and emulsify water into the internal phase of the mud in order to maintain the oil mud nicely. Surface active additives, which typically have molecules with a polar end and a nonpolar end, are used to produce emulsification and wetting. They are kept at an excessive concentration in the mud in order to coat any created drilled solids and emulsify any water inflow from the formation. The oil phase of the mud contains those additional concentrations, which means the filtrate from the mud can hold them and enter the formation. There, they could assemble at oil-water, oil-rock, or water-rock interfaces and alter surface interactions [23].

Growing temperature has the effect of reducing the quantity of harm done to the test fluid. The surfactants may have degraded as a result. However, the difference between the minimum and maximum mobility discount is now only 3%. It was found that the flowrate variable was far less significant than the system temperature. The amount of emulsification depends on the flowrate since it controls the shear at the desk-bound fluids inside the core. Even while certain particle redistributions within the core are likely, the artificial filtrate's artificially altered or reversed wettability and emulsion blocking caused an almost complete loss in mobility for all of the tests. [23].

2.2.3. Mud induced Damage in Fractured Reservoir:

Some of the most productive reservoirs in the world get almost all of their production via networks of fractures inside the producing pay that cross the wellbore. Even though the matrix permeability is quite poor, these cracks offer perfect permeability for oil and gas to flow into the wellbore. It has been discovered generally that drilling through these producing periods using muds made of water or oil results in significant productivity losses. Even when drilling is carried out in an unbalanced environment, those reductions are occasionally observed.

Therefore, it is surprising that so little research has been done to examine formation damage in such fragmented reservoirs [17].

Lost circulation materials are often made to accomplish two tasks: (1) to span the faces of existing fractures or vugs, and (2) to prevent the propagation of any fractures that might be precipitated during drilling. This method has led to the creation of a wide range of additives that seem to function under some circumstances but not others. A few common rules of thumb seem to apply to problems with lost circulation.

- Muds with an oil foundation are more likely to experience circulation problems than muds with a water base.
- The fluid-loss additive's size distribution, attention, form, and application technique are crucial to a treatment's effectiveness.
- Without bridging chemicals in the drilling mud, drilling through a fractured reservoir will severely damage the fracture system due to high permeability.
- Drilling mud can be used to fill the fracture, and the permeability loss isn't usually completely restored by flow back [17].

2.3. Formation Damage caused by Workovers Operations:

Well productivity can be increased if clean fluids are applied during workovers and completions. Any clay, silt, or sand that is suspended in wellbore fluids has the potential to deposit inside the producing formation and the perforation channels, where it may slow down a well's rate of production. Fluids are frequently cleaned using filters. Despite the fact that -micron cotton filters are typically used for this purpose, different filter types and filtration systems are available that would do the same task more effectively for less money [26].

A drilling fluid is created at some time during the drilling phase of the well to improve drilled cuttings and other particles. Drilling machinery is made to function in such particle-rich conditions. Fluids used for crowning splendor are not meant to enhance or suspend solids. In wells with such solids, many completion components (packers, wireline tools, isolation valves, etc.) cannot be installed or used. A fluid is needed to control wellbore pressure throughout the completion phase while also protecting the reservoir and the completion assemblies, which stay underground for the duration of the well. This is achieved by employing the last solids and drilling fluid to be displaced into the well after the drilling stage. Wellbore pressure is regulated by a clear, solids-free completion fluid, with density provided by the amount of dissolved salt in the apparatus. The fluid is also kept solid-free using standard diatomaceous earth (D.E.) filtration and/or pod filtration. As the fluids are circulated out of the well, this filtration process takes place on the low-pressure outflow of the circulating system. Although traditional filtration reduces the size of particulates in the fluid to two microns or less, this does not guarantee that the fluid will stay in the same country when pumped into the well. The solids-free finishing fluid can become overly contaminated by inadvertent contamination, poor rig-site maintenance, and inadequate rig cleaning. Grease, rust, barite, bentonite, plastic fragments, and other trash are the most often found materials. Pits, lines, and valve bodies downstream from the diatomaceous earth filtration unit are the main sources of wellbore debris. Iron oxide scale, which peels off from the inside of the lines, is one of the main types of waste. Additionally, there are numerous distinct types of harmful particles [26].

2.3.1. The Concept Minimize of Underbalance pressure:

The loss of the underbalanced pressure state during Underbalanced drilling (UBD) activities is a significant risk factor for formation damage. Therefore, it becomes crucial to assess the formation's sensitivity to the effects of an overbalanced pulse state of affairs. Four UBD drilling fluids have been used in tests that were both overbalanced and underbalanced. Under two different pressure circumstances (underbalanced and overbalanced), core testing comprises measurements of the initial and return permeabilities. A key aspect of optimizing the development of an oil field is minimizing formation damage, particularly in fractured carbonate reservoirs that frequently exhibit low matrix permeability. Minimizing fluid invasion could be crucial in these kinds of reservoirs because drilling fluid invasion into fractured formations can lead to severe formation damage around the wellbore, reduce well productivity, and ultimately reduce field recovery. Underbalanced drilling (UBD) is the process of drilling in which the pressure of the drilling fluid within the borehole is kept lower than the pressure of the formation in the open-hole portion. Within the industry, underbalanced drilling is well known for its increased productivity. Successful UBD can significantly reduce or even eliminate mud incursion into the fracture structures. Despite the various advantages UBD has over OBD, quantification of possible formation harm outcomes by comprehensive reservoir characterization and feasibility studies is significant to decide the feasibility of UBD.

If properly implemented, underbalanced technology may be very effective at reducing or eliminating formation damage, although the majority of this research has focused on issues that are frequently associated to UBD and the development of specific protocols for the proper design and implementation of UBD programs. In this study, two main objectives—improving a fractured reservoir's productivity through the use of UBD and reducing formation damage during UBD—are assessed. Even if an underbalanced pressure situation is maintained continuously throughout the drilling process, it is still possible for formation damage to result. all other The absence of the underbalanced pressure state at some point during UBD operations is one of the most significant regions of susceptibility to formation damage. Therefore, it is crucial to determine how sensitive the formation is to the effects of an overbalanced pulse state.

Excessive permeability features in a formation, such as large fractures or interconnected vugular porosity systems, present a significant challenge during overbalanced drilling operations due to rapid and deep penetration as well as potential permeability impairment. While these features can facilitate gas or oil production in some cases, primarily through matrix production in the immediate vicinity of the wellbore, it is crucial to protect the high-permeability fractures and vugs. They serve as conduits for transporting gas or oil from limited source matrices to the wellbore for production. However, in most situations, relying on the high permeability of these fractures and vugs requires careful consideration and protection to ensure optimal production [16].

2.3.2. Acidizing & Formation Damage:

Hydrochloric acid is used in conventional matrix acidizing procedures to encourage carbonate production. However, the effectiveness of these treatments is frequently limited by rapid acid consumption at low injection costs and the precipitation of asphaltic sludge. Acidizing solutions are frequently applied to carbonate formations to remove damage that is close to the wellbore and construct artificial flow channels. When fracture acidizing is undesirable, such as when a shale wreck or other natural boundary should be maintained to preserve your water or gas production, matrix acidizing treatments are most advantageous. When hydrochloric acid is injected into carbonate deposits at low rates, the carbonate matrix adjacent to the wellbore faces dissolving or completely dissolves. This face dissolution calls for massive volumes of acid and provides negligible will increase within the conductivity of the formation.

To address the challenges associated with rapid acid consumption at low injection rates, various acid systems have been developed. These include:

Mild acids with low H+ concentrations, such as acetic and formic acid, which react more slowly with carbonates compared to HCl.

Chemically retarded acids, such as HCl-based oil external micro emulsion systems, which enable deeper penetration of the acid and prevent its spreading outside the main dissolution channel.

Foamed acids, consisting of nitrogen gas and aqueous HCl, which not only confine the acid within the main dissolution channel but also promote the formation of wormholes.

These acid systems offer alternative approaches to enhance acid performance and overcome limitations associated with injection rates and acid distribution [27].

While weak acids, such as HCl, can precipitate asphaltic sludge from crude oil at higher injection rates, retarded and foamed acid systems can trigger carbonate forms at lower injection rates. After an acidifying treatment, this sludge can block the formation and impede production. This issue becomes significantly worse when ferric ions are present. Therefore, appropriate corrosion prevention is more crucial than ever. Acetic acid, an iron chelating agent, no longer reduces aggressive tendencies when ferric and ferrous iron are present. In order to stop the problem with slugging, anti-slugging agents, corrosion inhibitors, and iron reduction products were utilized. However, the desire to acquire a well-matched combination of components and a lack of knowledge of the intricate chemistries involved in the precipitation reactions limit their efficiency. These obstacles highlight the need for an alternate stimulation fluid that combines the ability to stimulate at low injection rates with fluid houses that do not promote the precipitation of asphaltic sludge or corrosion problems [27].

Chapter 3

3. Methodology

Sandstone samples are collected from different resources, mainly from the Indus Basin, which is known for its significant sandstone deposits. The collected samples can be in two forms**:** plug form or core form, depending on the availability and intended use. If the samples are received in plug form, they are used directly for porosity and permeability measurement, as plugs are already in a suitable shape and size for these specific analyses. However, if the samples are in core form, which are cylindrical rock samples extracted from the subsurface, they need to undergo a plug formation process to create smaller, representative plugs for subsequent analysis.

The Core Preparation Laboratory at the Department of Petroleum Engineering, NED UET, plays a crucial role in the plug formation process. It provides specialized facilities and equipment required for transforming the core samples into plugs of desired dimensions. After the plugs are formed, it is important to ensure that they are free from any external contaminants or impurities that could interfere with the subsequent analysis.

Therefore, the prepared plugs undergo a thorough cleaning procedure. Once the cleaning process is complete, the plugs are then placed in an oven for drying. This step is crucial to remove any remaining moisture, which could affect the accuracy of porosity and permeability measurements. The dried and prepared plugs are now ready for further experiments, analysis, or characterization, such as porosity measurements, permeability tests, or other relevant investigations. It is important to note that the entire sample preparation process follows established protocols and quality control measures to ensure reliable and accurate results. The sample preparation process concludes at this stage, and the prepared samples can be used for subsequent studies or to support research and development in the field of petroleum engineering or related disciplines.

The methodology used in this experimental work for sample preparation is showing by the following:

3.1. Sample Preparation for Porosity & Permeability:

Collection and cutting of boulder rock to obtain a fixed shape: In order to perform porosity and permeability tests on rocks, it is necessary to obtain representative samples. Large boulder rocks are collected from the field, and then they are cut into smaller, fixed shapes using specialized equipment. This ensures that the samples are of appropriate size and geometry for testing.

Marking of obtained core sample to take out plug: Once the boulder rock is cut into a manageable size, the core sample is marked to indicate the location from which the plug will be extracted. This marking is important to ensure that the plug is taken from the desired section of the sample, typically representing the most relevant part of the rock for porosity and permeability analysis.

Cutting of the sample according to the marking: The marked core sample is then carefully cut using precision tools, files and Damp cloth, to extract the plug. This process requires skilled technicians who can accurately follow the markings to obtain a precise plug that represents the desired section of the rock.

For obtaining the required plug, plugging is done: Plugging refers to the process of extracting a cylindrical or cuboidal-shaped specimen, known as a plug, from the core sample. The plug is extracted using drilling or coring techniques, which involve drilling into the marked section and retrieving the desired sample. The plug obtained from this process will be used for porosity and permeability measurements.

Samples will be trimmed and end face ground: After the plug is extracted, it may undergo further preparation steps. This can include trimming the plug to remove any irregularities or unwanted portions, ensuring that the sample has a uniform shape and size. The end face of the plug may be ground to achieve a smooth and flat surface, which is crucial for accurate porosity and permeability measurements.

Samples will be cleaned and dried: Prior to conducting porosity and permeability tests, it is essential to clean the samples to remove any impurities that may interfere with the measurements. The plugs are typically cleaned using solvents and brushes to remove any dirt, dust, or other contaminants. After cleaning, the samples are dried thoroughly to ensure consistent and reliable test results.

3.1.1. Sample Mud Preparation:

Selection of type of Mud: Mud, also known as drilling fluid, is used during the drilling process to facilitate the removal of cuttings, cool the drill bit, and maintain stability of the wellbore.

The selection of the appropriate type of mud depends on various factors such as the formation being drilled, wellbore conditions, and the objectives of the drilling operation. Different types of mud, such as water-based mud, oil-based mud, or synthetic-based mud, may be chosen based on the specific requirements of the drilling project.

Selecting the chemicals: Mud preparation involves the addition of various chemicals to enhance its performance and tailor it to specific drilling conditions. Different chemicals are selected based on their desired properties, such as viscosity, density, lubricity, filtration control, and inhibiting properties. Examples of chemicals commonly used in mud preparation include polymers, clays, weighting agents, Viscosifiers, emulsifiers, and pH control agents.

Collection of hydrated clays: Hydrated clays, such as bentonite, are commonly used in mud preparation due to their excellent properties for fluid retention, viscosity control, and filtration control. These clays are collected and processed to remove impurities and ensure consistent quality. Hydrated clays swell when mixed with water, forming a gel-like substance that helps maintain the stability of the wellbore and prevents the influx of formation fluids.

Preparation of mud: The process of mud preparation involves mixing the selected type of mud with the appropriate chemicals and additives. This is typically done in mud tanks or mixing units, where the mud components are blended together to achieve the desired properties. The mixing process is carefully controlled to ensure uniform distribution of chemicals and proper hydration of clays. The mud is continuously monitored and adjusted to maintain its properties throughout the drilling operation.

3.1.2. Porosity Measurement of Sandstone core plugs:

- **Porosity:**

The porosity governs the storage capacity of rock or, in other words, the oil and gas contained in unit volume of rock.

Porosity (φ) is the ratio of the total void space within a rock (the pore volume) to the total bulk volume of that rock i.e.

$porosity$ = φ = (Pore volume / Bulk Volume)

$$\varphi = \frac{\text{Bulk Volume} - \text{Grain Volume}}{\text{Bulk Volume}} = \frac{\text{Pore Volume}}{\text{Bulk Volume}}$$

The Measurement of the bulk volume can be done by different techniques, for example, Archimedes immersion and callipering. Every method has its own advantages and disadvantages with known limitations. In this study, we have used calipering.

3.1.3. Physical Parameters of core plugs:

The selection of core plugs from the specific producing formation is crucial as it ensures that the samples represent the geological characteristics and reservoir conditions of interest. By focusing on the lower Indus basin and the PAB formation, the experiment aims to study the porosity and permeability properties of sandstone reservoirs in this particular geological context.

The properties of the core plugs play a significant role in understanding the reservoir behavior and estimating its productivity. The length of the core plug provides insights into the sample's thickness, while the diameter helps determine its cross-sectional area. These measurements, along with the weight, aid in calculating the porosity and permeability of the sandstone samples, which are fundamental parameters for evaluating reservoir quality and fluid flow characteristics.

In this experiment, core plugs obtained from the producing formation of the lower Indus basin, the PAB formation, were used. These core plugs primarily consist of sandstone, a prevalent rock type in the region. The properties of the core plugs, including their length, diameter, and weight, are provided in ***Table 0-1***.

Core #	**Length (mm)**	**Diameter (mm)**	**Weight (g)**
1	53	31	70.52
2	44	25	49.51
3	49	25	54.62

Table 0-1 Physical parameters of the core samples

3.2. Experimental Procedure:

Establishing communication between the Pycnometer and PC: The first step is to ensure that the pycnometer, which is the instrument used for porosity measurement, is properly connected to the computer (PC). This is done by starting the software specifically designed for porosity measurement and verifying that the communication between the pycnometer and PC is successfully established.

Connecting the communication cable: The communication cable is plugged into both the PC and the console of the pycnometer to establish a connection. This cable allows data transfer between the pycnometer and the computer, enabling real-time monitoring and control during the measurement process.

Setting the console pressure: Before starting the porosity measurement, the console of the pycnometer is set to a specific pressure. In this case, it was set to 100 pounds per square inch (psi). This initial pressure setting ensures consistent and controlled conditions for the measurement.

Calibration with billets: To validate the accuracy of the Porosimeter system, the s matrix cup, which is a part of the pycnometer, is filled with billets. These billets serve as reference materials with known porosity values. By comparing the measured porosity of the billets to their known values, the accuracy of the Porosimeter can be assessed. It is essential to have an error-free system after calibration, indicating that the porosity measurements obtained will be accurate.

Placing sandstone core plugs in the Matrix Cup: Once the Porosimeter system is calibrated and verified to be error-free, the sandstone core plugs are inserted into the 1-inch Matrix Cup. The Matrix Cup is a vessel designed to hold the sample during porosity measurement. Along with the sandstone core plugs, additional billets may be included to establish a reference pressure.

Setting the reference pressure and starting the measurement: The reference pressure for the measurement is set to 100 pounds per square inch (Psi), maintaining consistent conditions. With the sandstone core plugs and reference pressure in place, the porosity measurement is initiated using the software interface on the PC. The Porosimeter system measures and records the porosity values of the sandstone samples.

Sandstone samples used in the experiment: Table 0-1 showcases the sandstone samples that were utilized in these porosity measurement experiments. The visual representation of the samples provides a reference for the rock types and characteristics analyzed during the study.

Figure 0-1 Core samples used in the experiments

The same procedure was followed for all samples and results were obtained. ***Figure 0-2*** shows the schematic of the apparatus.

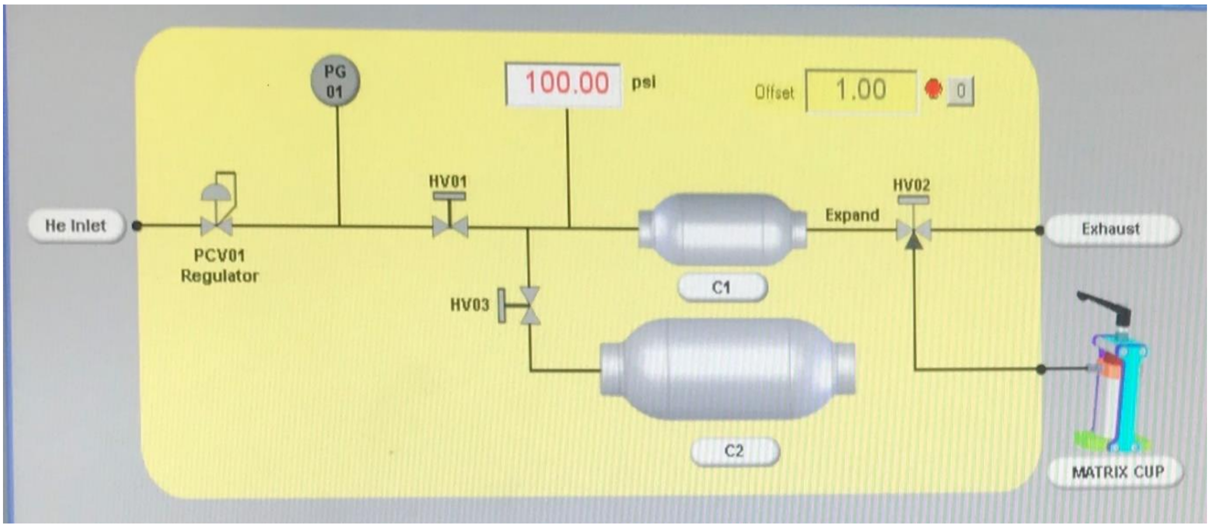


Figure 0-2 Schematic of the Porosimeter

3.2.1. Results of Measurements:

After successful measurements have been performed on the core plugs, following results for porosity measurements have obtained. ***Table 0-2*** shows the porosity of the sandstone core samples.

Core #	Length (mm)	Diameter (mm)	Weight (g)	Bulk Vol (cc)	Grain Vol (cc)	Pore Vol (cc)	Grain Density (g/cc)	Effective Core Porosity (%)
1	**53**	**31**	**70.52**	**28.1**	**23.8**	**4.36**	**2.97**	**15.3**
2	**44**	**25**	**49.51**	**21.6**	**19.5**	**2.12**	**2.54**	**9.8**
3	**49**	**25**	**54.62**	**24.1**	**21.5**	**2.52**	**2.54**	**10.5**

Table 0-2 Results of porosity of core samples

3.2.2. Mud Preparation:

Mud for the experiments were prepared in the mud lab of Petroleum Engineering department, NED University. Mud preparation was done under the supervision of research supervisor.

One of the key objectives is to closely monitor the properties of the mud in order to gain a comprehensive understanding of its behavior. This monitoring process is crucial to ensure that the prepared mud aligns as closely as possible with the industry-standard practices. By replicating the industry environment, the study aims to achieve its goals effectively.

Throughout the preparation of the mud, utmost importance was given to health and safety measures. Stringent protocols were followed to ensure the well-being of all individuals involved in the process. These measures not only guarantee the safety of the personnel but also contribute to the overall integrity of the study.

As the experiments for mud preparation were carried out in the lab, so we have taken as 1 bbl field unit as 345 ml (lab bbl). 345 ml of Mud contains (Water + Additives).

1 field bbl = 350 (lab bbl)

3.2.3. Basic Methodology:

It is crucial to maintain a neat and clean laboratory environment during mud preparation to prevent any contamination. Here are some important points to consider and further enhance the methodology:

- The mud preparation area was located away from potentially hazardous chemicals to provide a clear view for all personnel working in that specific area. This ensures their safety and allows for better supervision.
- Proper storage of equipment was emphasized when not in use. This includes securely storing all tools and materials to prevent damage or contamination. Implementing a systematic storage system can contribute to overall efficiency and organization.
- The use of personal protective equipment (PPE) was strictly enforced during mud preparation. All personnel involved were required to wear appropriate PPE, such as gloves, safety goggles, and lab coats, to protect themselves from potential hazards and maintain a safe working environment.
- Regular inspections were conducted to ensure there were no damaged sacks or bottles of chemicals in the laboratory. If any damages were identified, immediate action was taken to repair or replace them. This practice helps prevent accidents and the unnecessary disposal of chemicals.
- A vigilant supervisor was assigned to oversee the mud preparation process. The supervisor's role included ensuring that all necessary precautions were in place and consistently followed. This proactive approach promotes safety awareness and helps prevent potential risks.

➢ **Water base mud (salt polymer + Glycol) continuous phase is water**

- Water-based mud is a type of drilling fluid primarily composed of water, which is supplemented with additives to enhance its performance and effectiveness. This type of mud typically includes bentonite and heavy minerals to increase its weight and improve drilling operations.
- One crucial point to emphasize is that water-based mud, with a water content ranging from 70 to 80 percent, is widely utilized as the preferred drilling fluid for various drilling applications in the United States. This highlights its extensive usage and reliability in different drilling scenarios.
- Moreover, it is essential to mention that the additives used in water-based mud serve the purpose of modifying the fluid's properties to optimize drilling performance. These additives can include various chemicals, polymers, and Viscosifiers, among others. The

specific additives chosen depend on the drilling objectives, geological conditions, and environmental considerations.

- Furthermore, the benefits of water-based mud can be highlighted, such as its lower environmental impact compared to oil-based mud. Water-based mud is generally easier to handle, dispose of, and poses fewer risks to the environment. Additionally, it allows for better wellbore stability and helps mitigate formation damage during drilling operations.
- Lastly, it is crucial to discuss the challenges and limitations associated with water-based mud, such as its susceptibility to contamination and its reduced tolerance for high-temperature environments. These aspects need to be addressed and mitigated through proper monitoring, testing, and maintenance procedures.

➢ **Polymer system:**

Polymers of long chains, high molecular weight will use to encapsulate cuttings to prevent dispersion and cost shale for inhibition. They will also use to increase viscosity and reduce fluid loss. A verity of polymers will add for those purposes such as cellulose and natural gum based products KCL and NaCl are added to provide higher stability. The polymer system is temperature limited system; they cannot be use for temperature higher than 300 ^oF [25].

3.2.4. Composition of Mud

As discussed earlier to meet the field conditions we have prepared 1 bbl of mud in the lab, which is equal to 350 ml (lab bbl). This 345 ml of mud includes water and the other additives used in the preparation of mud. (1 field bbl = 350 (lab bbl))

3.2.5. Preparation procedure:

- Measured 309 ml of water in a beaker and poured it into the mixing container.
- Added all the pre-measured additives (Shown in ***Table 0-3***) according to the required composition of the mud.
- Ensured that the Hamilton Beach mixer was securely plugged into a properly installed electric output.

- Placed all the ingredients in the mixing container to be mixed.
- Initiated the mixing process at a normal speed and gradually increased the speed for better and proper mixing.
- Ensured a clean and sanitized work environment to prevent contamination.
- Used precise measuring techniques and equipment to ensure accurate measurements of water and additives.
- Followed any specific instructions provided by the manufacturers of the additives and mixer for optimal performance.
- Conducted regular quality control tests during the mixing process to monitor the properties of the mud.
- Documented all steps, measurements, and observations for future reference and analysis.

The following points must be considered and must be carefully observed and treated while preparing the mud.

- **Water treatment:**

water treatment is a crucial aspect that significantly impacts the performance of the mud. It is essential to ensure that the water used is free from impurities and chemical effects in order to achieve the desired results. The presence of ions such as Ca^+ or Mg^+ in the water can have detrimental effects on the mud's characteristics.

When calcium and magnesium ions are present in the water, they can replace sodium ions in the mud. This substitution leads to a reduction in hydration, increased flocculation, and aggregation of mud particles. Consequently, there is an increase in gel strength, fluid loss, and yield point of the mud. Monitoring the concentration of these ions in the mud filtrate becomes essential due to these reasons. Moreover, the presence of such ions can decrease the efficiency of polymers used in the mud.

To mitigate the effects of calcium ions in the water, the addition of sodium ash can be employed. Sodium ash helps counteract the impact of calcium ions. On the other hand, if magnesium ions are present in the water, caustic soda ($NaOH$) can be used to neutralize their effects.

- **Fluid loss control:**

Fluid loss control is a critical aspect of mud preparation in drilling operations. One commonly utilized additive for this purpose is Polyanionic Cellular (PAC). PAC is a widely popular choice due to its ability to effectively decrease water loss and mud cake thickness.

PAC is characterized by its low viscosity, technical grade, and dispersible nature. These properties make it an ideal additive as it minimally affects the viscosity of aqueous drilling fluids while significantly reducing the API filtration rate. This means that PAC can effectively prevent filtrate loss during drilling operations.

To achieve optimal fluid loss control, a specific variant of PAC known as Polyanionic Cellular-L (PAC-L) is often employed. PAC-L is specifically designed to minimize filtrate loss, ensuring the integrity and stability of the drilling fluid system.

Fluid loss control is a critical objective in drilling operations, and PAC is a widely used additive that effectively addresses this issue. PAC's low viscosity, technical grade, and dispersible nature make it an excellent choice for minimizing water loss and mud cake thickness. By reducing the API filtration rate, PAC-L variant in particular ensures minimal filtrate loss and helps maintain the stability of the drilling fluid system.

The table below shows the composition of the prepared mud; these were determined in the Labs of Petroleum Department.

Product	**Salt, Polymer, Glycol**
Sample composition	**PPB**
Water in ml	309
Soda ash	0.25
KCL	18
Polyanionic cellulose-L	3
PHPA	0.5
Xanthan gum	0.75
Glycol	3% by volume
Barite	75

Table 0-3 Composition of Mud

Figure 0-3 Hamilton beach mixer (NED mud Lab)

- **Viscosifier:**

Fluid loss control is a crucial aspect of mud formulation in drilling operations. Viscosifiers play a vital role in achieving this control for two primary reasons:

Suspending barite: Barite is a commonly used weighting material in drilling mud. Viscosifiers are necessary to suspend barite particles uniformly throughout the mud. This ensures proper density control and prevents settling of barite, which could lead to uneven weight distribution in the wellbore.

Increasing cutting carrying capacity: Drilling mud serves as a medium for carrying drilled cuttings to the surface. Viscosifiers enhance the carrying capacity of the mud by increasing its viscosity. This helps to effectively transport the cuttings out of the wellbore, preventing clogging and improving overall drilling efficiency.

One commonly used viscosifier is xanthan gum, which exhibits unique properties when added to water. Xanthan gum is a long-chain polymer that significantly increases viscosity, surpassing even plastic viscosity, which is a fundamental property of any viscosifier. However, xanthan gum has limitations in terms of fluid loss control.

Despite its excellent thickening abilities, xanthan gum has poor fluid loss control characteristics. Therefore, it is primarily employed for increasing the viscosity of the mud rather than reducing fluid loss.

To illustrate the rheological properties of the mud formulated in the Petroleum Engineering Department's mud lab, ***Table 0-4*** provides valuable insights. This table showcases the specific rheological parameters such as viscosity, yield point, and plastic viscosity, which are crucial for assessing the flow behavior and performance of the mud.

Fluid loss control is a critical aspect of mud formulation in drilling operations. Viscosifiers, such as xanthan gum, are necessary to suspend barite particles and increase cutting carrying capacity. While xanthan gum is effective in enhancing viscosity, it has limitations in fluid loss control. The provided ***Table 0-4*** offers valuable information on the rheological properties of the mud prepared in the Petroleum Engineering Department's mud lab, aiding in the understanding and assessment of its flow behavior.

Parameter	Unit	value
RHEOLOGY	TEMP-F	90
Gels 10”	Lbs/100ft2	4
Gels 10’	Lbs/100ft2	3
PV	Cp	15
YP	Lbs/100ft2	12
API Fluid loss	MI	7
cake API	1/32”	1
Ph		9.1
MUD WEIGHT	Ppg	10

Table 0-4 Rheology of the Mud

- **Inhibitors:**

In mud preparation, various inhibitors are utilized to enhance the performance and stability of the drilling fluid. These inhibitors include salt, potassium chloride (KCl), silicates, glycol, and Polyacrylamide-based Partially Hydrolyzed Polyacrylamide (PHPA), commonly referred to as an encapsulator.

The addition of inhibitors serves multiple purposes in mud formulation. They help mitigate potential issues and improve the overall efficiency of the drilling process. One key function of inhibitors is to prevent further breakdown of cuttings. In this regard, PHPA, known as an encapsulator, plays a crucial role. The encapsulator acts as a protective barrier, preventing the cuttings from undergoing further fragmentation or disintegration.

In addition to PHPA, other inhibitors such as salt, KCl, silicates, and glycol are employed for their specific properties. Salt is utilized to enhance the density of the drilling fluid, enabling better control of well pressure and preventing fluid influx. KCl serves as a shale stabilizer, minimizing the dispersion of shale particles into the drilling mud. Silicates contribute to the inhibition of clay swelling and help maintain the stability of the mud system. Glycol, on the other hand, acts as a hydrate inhibitor, preventing the formation of gas hydrates that can obstruct drilling operations.

By employing these inhibitors, the drilling fluid is optimized to prevent further breakdown of cuttings and address various challenges encountered during drilling. The encapsulator, PHPA, provides an additional layer of protection for cuttings, ensuring their integrity throughout the drilling process. Salt, KCl, silicates, and glycol contribute to the stability and performance of the mud system, controlling density, stabilizing shale, inhibiting clay swelling, and preventing hydrate formation, respectively.

Overall, the selection and utilization of these inhibitors are critical for maintaining drilling efficiency, protecting cuttings, and ensuring the stability of the mud system.

Figure 0-4 Prepared water based mud

- **Weighting agents:**

In mud preparation, barite serves as a crucial weighting agent. Its primary function is to enhance the density of the drilling mud, thereby increasing the hydrostatic pressure within the well. This increase in pressure plays a vital role in reducing the risk of blowouts, a potentially dangerous situation in drilling operations.

By incorporating barite into the mud, the overall density of the fluid is raised, providing the necessary counterforce against the pressure exerted by the formations encountered during drilling. This increased hydrostatic pressure helps maintain wellbore stability, preventing the uncontrolled release of fluids or gas from the formation and minimizing the risk of a blowout.

To visualize the mud prepared in the mud lab and gain insights into its characteristics, ***Figure 0-4*** is provided. This figure offers valuable information regarding the composition and properties of the mud. It may include details such as barite concentration, density measurements, and other relevant parameters that are essential for assessing the effectiveness of the mud in maintaining hydrostatic pressure and mitigating blowout risks.

- **LCM material:**

Loss control materials play a vital role in the industry to effectively manage and prevent the loss of drilling mud. However, in the context of this laboratory-based project, specific loss control materials were not utilized in the preparation of the mud.

Loss control materials are typically employed to address fluid loss issues that may occur during drilling operations. These materials are designed to minimize the loss of drilling mud into the formation, ensuring the integrity and stability of the wellbore. They can include additives such as fluid loss control agents, bridging agents, or even specialized mud systems like invert emulsion or foam.

In the laboratory setting of this project, the focus was likely on other aspects of mud formulation, such as viscosity control, density adjustment, or specific performance characteristics. Loss control materials were not incorporated as they were not deemed necessary or within the scope of the project.

It is important to note that the absence of loss control materials in the laboratory-based mud preparation does not diminish the significance of these materials in real-world drilling operations. Loss control measures are crucial for maintaining wellbore stability, preventing costly mud losses, and ensuring drilling safety.

3.3. Experiments for initial permeability determination:

The objective was to measure the initial permeability of core samples and analyze the impact of mud interaction on the permeability. By comparing the permeability before and after exposure to mud, it is possible to assess the extent of damage caused by the interaction.

To conduct the experiments, various apparatus was utilized, including:

- Vernier caliper: Used for accurate measurement of core sample dimensions.
- Weight balance: Employed to determine the weight of core samples and other materials.
- Gas permeability meter: Utilized to measure the permeability of the core samples.
- Mud mixer: Used for preparing the mud samples according to the specified composition.
- Beakers: Containers used to hold and handle the mud samples during the experiment.
- Tap water: Used as a component in the preparation of the mud samples.
- Chemicals: Additional chemicals were employed in the formulation of the mud samples.
- Oven extractor:

The mud samples used in the experiments consisted of two types of water-based mud:

- Water-based mud (salt+ polymer+ glycol): This mud formulation included salt, polymer, and glycol as key components.
- Water-based mud (salt+ polymer+ barite): This mud formulation comprised salt, polymer, and barite.

By using these specific mud formulations, the experiments aimed to evaluate the impact of different mud compositions on the permeability of the core samples.

This involved conducting experiments to measure the initial permeability of core samples and assess the damage caused by the interaction with mud. Various apparatus, including Vernier caliper, weight balance, gas permeability meter, mud mixer, beakers, tap water, and chemicals, were utilized. The experiments involved two types of water-based mud: one containing salt, polymer, and glycol, and the other containing salt, polymer, and barite.

These experiments aimed to provide valuable insights into the effects of mud composition on core sample permeability.

3.3.1. Properties of formation used:

These core plugs were issued by the renowned petroleum exploration and production company ENI (inti) Pakistan, the properties of the core samples are.

- These core samples will have obtained from lower Indus basin.
- These core samples are from PAR formation.
- These core samples are of producing formation

The physical properties of the core samples are given below in **Table 3.5**

Core #	Length (mm)	Diameter (mm)	Weight (g)
1	53	31	70.52
2	44	25	49.51
3	49	25	54.62

Table 0-5 Physical parameters of samples for initial permeability determination

3.3.2. Introduction to Gas Permeability Meter:

The Gas Permeability Meter available at the Petroleum Engineering Department's laboratory at NEDUET is a research-grade instrument that proves to be useful not only for routine core analysis but also when rapid and comprehensive results of core testing are required. This instrument is efficiently managed and consistently delivers promising outcomes.

The Gas Permeability Meter is equipped with specific features and specifications that allow for precise control of steady-state gas flow and core pressure within a range of 0-2000 cc/min and 0-200 psi. This capability enables excellent command and control over Darcy flow conditions in cores with permeabilities ranging from less than 1 md (Milli Darcy) to 10 D (Darcy).

To accurately measure permeability, the Gas Permeability Meter is equipped with two mass flow meters connected to the equipment. These meters, along with an 8 psid differential pressure transmitter, are responsible for sensing gas flow and pressure drop across the core sample. It is crucial to ensure correct calibration of the transmitters to obtain the most precise permeability measurements.

The versatility of the Gas Permeability Meter is exemplified by its compatibility with any type of Hassler-type core holder. This unique quality allows for the utilization of different core holders with varying diameters, such as 1" and 1.5", or any other desired diameter. Additionally, the instrument enables the application of confining pressures of up to 400 psig on the cores, with the pressure readings displayed on the Gas Permeability Meter console.

- **Basic formulas:**

When determining the permeability of a porous medium, it is important to note that there are distinct formulas for liquid and gas flow. This distinction arises from the fundamental difference between liquid, which is considered an incompressible fluid, and gas, which is considered a compressible fluid.

Liquid flow in a porous medium follows the principles of incompressible fluid mechanics. As a result, the formulas used to calculate liquid permeability are based on the assumption that the fluid is not subject to compression under the prevailing conditions.

On the other hand, gas flow in a porous medium involves the dynamics of a compressible fluid. As gas flows through the core sample towards the downstream end, its pressure decreases. This reduction in pressure causes the gas to expand, leading to an increase in velocity.

The compressibility of gas introduces additional considerations and variables into the formulas used to determine gas permeability. These formulas account for the compressibility factor, pressure differentials, gas properties, and other factors that affect the flow behavior of gases in porous media.

Figure 0-5 Gas-Permeability meter

The Darcy equation for flow of gas under steady state isothermal condition is given in **Equation 3.1** as,

$$\text{Kgas} = \frac{2uZtPb}{ATb(P1-P2)2} \qquad \text{…………………} (3.1)$$

Where;

K_{gas}= Gas Permeability (D)

U= viscosity of gas (cp)

Z= Gas compressibility factor

T= Temperature of flowing gas

Pb= Atmospheric pressure (absolute atm)

L= length of sample

Qb= Atmospheric gas flow rate (cm/s) at base pressure Pb

A= Cross sectional area of cylinder (cm)2

Here,

Tb= Base temperature (ambient)

P1, P2= upstream and downstream absolute pressure respectively.

If the base temperature is equal to the mean temperature so the Z gas compressibility factor is taken as unity, which is nearly true for nitrogen under typical operating ambient conditions, and as we know the core pressure drop P= P1-P2 and the core mean pressure is,

$$\text{Pm} = \frac{P1-P2}{2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(3.2)}$$

Then, the above equation for Kg can be reduced less spreader expression:

$$Kgas = \frac{QbuLPb}{A\Delta PPm} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(3.3)}$$

Where;

U= viscosity of gas (cp)

Qb= atmospheric gas flow rate (cm/s)

L= length of sample (cm)

Pb= base or atmospheric pressure (absolute atm)

ΔP= differential pressure (atm)

Pm= mean core gas pressure (atm)

A= cross sectional area of cylinder (cm)2

If backpressure is used, then;

$$P1 = \frac{\text{P1(psig)}}{14.695949} + Pb(atm) \quad \ldots\ldots\ldots\ldots\ldots\ldots \text{(3.4)}$$

and;

$$P2 = \frac{P1(psig) - \Delta P(psid)}{14.695949} + Pb(atm) \quad \ldots\ldots\text{.. (3.5)}$$

Core mean pressure Pm is found from $Pm = \frac{P1+P2}{2}(atm)$ where P1 and P2 are calculated as in the above stage.

- **Measure the physical parameters of core sample:**

The physical parameters of the core samples, namely the length, diameter, and weight, were key factors in characterizing the samples. The measurements of these parameters were conducted using a Vernier caliper for length and diameter, and a weight balance for weight determination.

To ensure accurate weight measurements, each core sample's weight was measured twice throughout the experiment. The first weight measurement was taken before determining the initial permeability, providing a baseline reference. Subsequently, the core samples were subjected to mud interaction, followed by placement inside a moisture extraction oven to facilitate drying. After the drying process, the second weight measurement was obtained. It is essential to note that the first weight (weight 1) must be equal to the second weight (weight 2) for reliable analysis.

The repeated weight measurements serve as a means to monitor and assess any changes in the core samples' mass during the experimental stages. Consistency between weight 1 and weight 2 is crucial for accurate evaluation and interpretation of the impact of mud interaction and drying on the core samples.

By comparing weight 1 and weight 2, researchers can discern whether moisture has been gained or lost by the core samples. This information is pivotal in analyzing the effects of mud interaction and drying on the physical properties and behavior of the cores.

Core #	Length (mm)	Diameter (mm)	Weight (g)
2b	53	31	70.52
3c	44	25	49.51
5c	49	25	54.62

Table 0-6 Core sample physical parameters

- **Sample Operation:**

In the gas permeability meter experiment, a core sample with a diameter of 1" was used. It was ensured that the core sample had no irregularities or uneven ends, as this is crucial for accurate measurements. The selection of an appropriate core holder is of utmost importance and should be based on the diameter of the core sample.

To place the core sample inside the core holder, it was necessary to release the overburden pressure first. This was achieved by disconnecting the confining SS tubing from the core holder. Following this step, the inlet and outlet flexible tubing were disconnected and removed.

In cases where it was necessary to remove the sample from the core holder, it was vital to ensure that both the flow system and the confining system were depressurized. To accomplish this, the system was switched OFF, the ∆P valve was turned OFF, and the confining pressure was released gradually by switching to the VENT position at intervals until the pressure was completely released.

After depressurization, the sample could be safely removed from the core holder by giving it a controlled rotation.

These steps and precautions were taken to ensure the proper handling and extraction of the core sample within the gas permeability meter experiment. By following these procedures, researchers could minimize the risk of damage to the sample and ensure accurate and reliable measurements.

- **Flow system of the Experiment:**

The Gas Permeability Meter is an integral part of the experimental setup. It is connected to two nitrogen supplies, each capable of flowing at different pressures. One supply can flow at 100 psig, while the other can flow at 400 psig. The valve labeled Pressure/Vent controls the supply of nitrogen or air as the confining fluid to the core holder through the connected tube. The pressure acting on the core due to this confining fluid is displayed on a pressure indicator downstream of the valve.

The core differential pressure is sensed by a 0-8 psid differential pressure transducer. When the ∆P valve is ON, gas flowing out from the sample creates a pressure gradient across the negative and positive inlets of the differential pressure transmitters. On the other hand, if the ∆P valve is OFF, the gas flow bypasses the transmitter. The upstream pressure of the core is continuously monitored by the transmitter, which is set at approximately 10 bar or 145 psig.

To accurately measure and sense the flow rate of atmospheric gas, the ∆P valve is utilized. It allows for precise measurements over a range of 0-2000 cc/min. A switch valve is used to select the appropriate flow meter, depending on the range of core permeabilities being tested. For low-flow rates in the range of 0-20 cc/min, the Low flow valve is used. Conversely, the High valve is employed for higher flows within the range of 0-2000 cc/min, suitable for testing high-permeability core samples. In the backward testing position, gas is directed into the gas permeability meter via a micro-metering valve. This backward flow generates a backpressure within the core, and the magnitude of this backpressure depends on both the gas flow rate and the position of the metering valve.

Temperature determination within the gas permeability meter can be facilitated by an optional sensor designed to sense the gas flow temperature through the core. This temperature is displayed on both the instrument's front panel and the connected computer. If no temperature is recorded on the gas permeability meter, room temperature can be used as a reference to ensure accurate permeability measurements.

3.4. Procedure of Experiments

The Gas Permeability Meter was connected to the main supply, and the instrument was powered up by switching on the main switch. Prior to powering up, the regulators were ensured to be fully turned anticlockwise. The nitrogen regulators were then connected to the pressure/vent valve and the core nitrogen supply valve.

Next, a sample with a diameter of 1" was inserted into the core holder. The confining valve of the pressure/vent system was set to the pressure mode. Nitrogen supply was provided at a confining pressure of 110 psi to the core holder sleeve, which was displayed on the confining pressure gauge.

Since the experiment aimed to determine permeability using the backward flow mode, the gas leaving the core had to pass through the orifice of the metering valve. This generated pressure on the upstream side of the orifice, which was then transferred back through the core. As a result, the core differential pressure decreased while the back pressure increased, maintaining a set atmospheric flow rate. The primary objective of the backpressure mode was to ensure precise control of core pressure and flow rate while promoting laminar flow conditions.

Once the pressure and flow rate became stable, the differential pressure, flow rate, and gas temperature were recorded. These data were automatically generated by the gas permeability meter through its software, allowing for convenient and accurate data collection.

Understanding the proper setup and operation of the Gas Permeability Meter, as well as the significance of the backward flow mode, was crucial for conducting successful permeability experiments and obtaining reliable results.

For consequent permeability determination, maximum admissible pressure drop can be noted from Darcy Table 3.7

K (md)	**∆P (dp/inch)**
0.01 to 0.1	1.8
0.1 to 1	3.9
1 to 10	4
10 to 100	1.2

Table 0-7 Maximum admissible pressure drop

To initiate the backward flow mode, we closed the metering valve. Once the metering valve was closed, we selected the low flow valve. The switch was turned ON, and WE gradually opened the metering valve until the desired flow rate of 110 psi was achieved. Throughout this process, we carefully monitored and recorded the stable pressure conditions.

During the stable pressure conditions, we made note of the upstream pressure, differential pressure, gas flow rate, and temperature. These recordings were automatically generated by the instrument's installed software, ensuring accuracy and reliability.

It's important to note that in core samples with very low permeability, it may take several minutes for the pressure and flow rate readings to stabilize. Additionally, the pressure reduction after core sampling may also require some time. Therefore, we allowed sufficient time for the readings to stabilize before recording the final values.

After the final reading was recorded, we completely turned off the regulator valve to fully depressurize the core. The confining metering valve was then switched from pressure to VENT, and I safely removed the core sample from the core holder.

Understanding the steps involved in initiating the backward flow mode, monitoring pressure and flow rate stabilization, and properly depressurizing the core sample is essential for conducting accurate and successful permeability experiments.

Chapter 4

4. Discussion of results

4.1. Strategy:

The strategy employed in this study was driven by the recognition of the significant impact of formation damage. Formation damage is not simply a singular issue, but rather a complex problem that gives rise to numerous other challenges. Its effects can be seen in reduced well productivity, the need for acidizing interventions, and the overall lifespan of the well.

For all stakeholders in the petroleum industry, these consequences of formation damage translate directly into increased well costs. Neither petroleum engineers nor petroleum companies desire to incur higher expenses for their wells. Their primary objective is to efficiently and safely complete and produce wells while minimizing costs.

Thus, in this study, the focus was on understanding and mitigating the adverse effects of formation damage, with the ultimate goal of optimizing well performance and economics. By addressing the underlying causes of formation damage and implementing effective prevention or remediation measures, the industry can achieve cost savings, enhance production efficiency, and ensure the longevity of wells.

In this study, the discussion of results focuses on the formation damage caused specifically by drilling operations and drilling fluids. While there are various factors that can contribute to formation damage, we narrow our focus to these aspects due to their significant potential for harm.

Drilling operations and the choice of drilling fluids play a crucial role in the occurrence of formation damage. It is essential to emphasize the impact of drilling fluids as they can be the most detrimental mechanism if not given adequate attention. Neglecting the effects of drilling fluids can lead to severe consequences that compromise well productivity and longevity.

The strategy employed in this study focused on evaluating the impact of mud contamination on core sample permeability. Initially, the permeability of the core sample was measured to establish a baseline. Subsequently, the core sample was exposed to two types of mud: a water-based mud consisting of salt, polymer, and glycol, and a water-based mud containing salt, polymer, and barite.

By subjecting the core sample to the mud for a specific duration, we aimed to investigate the extent of damage caused by the fluids and assess the influence of contamination time on the mud's effect. After the interaction period, the core sample was thoroughly dried, and its permeability was measured once again. This allowed us to determine the magnitude of damage inflicted by the mud and examine any variations in permeability caused by different contamination durations.

The experiments were conducted using mud formulations prepared in the mud laboratory of the Petroleum Engineering Department at NEDUET. The selection of water-based mud compositions with varying additives enabled us to explore the specific impact of each component on the core sample's permeability.

The results of this study provide valuable insights into the behavior of different mud compositions and their effects on core sample permeability. The findings shed light on the role of contamination time in exacerbating formation damage and highlight the importance of carefully managing mud interactions to mitigate adverse effects.

4.1.1. Initial Permeability

The influence of confining pressure on permeability was investigated by recording the results at a constant 110-psi confining pressure, while keeping other factors unchanged. The initial permeability of the sandstone samples was measured, and the findings are presented in **Table 0-1,** illustrating the trends observed in the data.

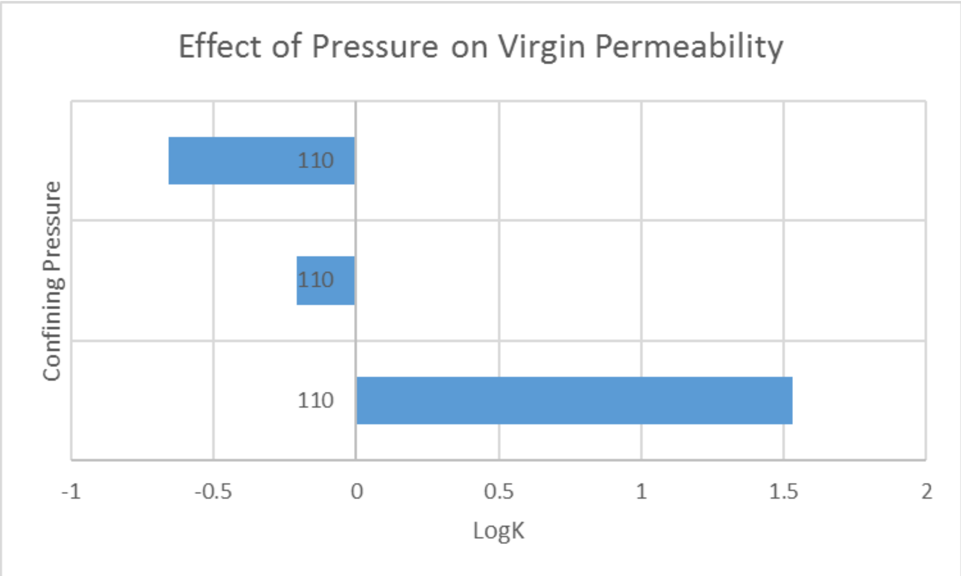
The recorded permeability values provide valuable insights into the behavior of the sandstone samples under varying confining pressures. The results indicate the relationship between confining pressure and permeability, enabling us to assess the impact of pressure on fluid flow through the porous medium.

By analyzing the data presented in **Table 0-1,** several important observations can be made. Firstly, it is evident that as the confining pressure increases, there is a corresponding decrease in permeability. This trend is consistent with the expected behavior of porous materials, where increased pressure leads to reduced pore space and restricted fluid flow pathways.

The obtained results also highlight the sensitivity of sandstone samples to changes in confining pressure. The recorded permeability values demonstrate the impact of confining pressure on the porosity and connectivity of the sample, influencing the ease of fluid movement within the porous structure.

Sample #	∆P (psi)	P (upstream)(psi)	P (confining)(psi)	K (md)
2b	3.089	3.14	110	**0.220**
3C	5.385	6.18	110	**0.622**
5C	5.633	4.93	110	**33.898**

Table 0-1 Initial permeability of core samples



As the Permeability values were small in range therefore Permeability values were taken with log in Excel to normalize the values to some extent.

Core differential pressure is sensed by 0-8 Psid differential pressure transducer, gas flowing out of the sample creates a pressure gradient across the positive and negative inlets of the differential transmitter.

Core upstream pressure was continuously sensed by transducer of the gas permeability meter approximately 145 psig.

The initial values of permeability were obtained and given in the table, which showed that samples have varying permeabilities.

4.1.2. Core samples interaction with Mud

Once the initial permeability measurements were completed, the mud preparation process commenced in the mud laboratory of the Petroleum Engineering Department at NEDUET. The samples were subjected to a 48-hour interaction with the prepared mud, during which they were carefully positioned and maintained in a stable condition within the Mud lab.

After the designated interaction period of 48 hours, the samples were removed from the mud and underwent thorough cleaning to eliminate any residual mud particles or contaminants. This cleaning step was crucial to ensure the integrity and accuracy of subsequent drying stages.

4.1.3. Moisture Extraction Oven

In the moisture extraction process, a moisture extraction oven was utilized to effectively remove moisture from the core samples. The following procedure was implemented to carry out this process:

- The core samples were carefully placed inside the moisture extraction oven.
- The temperature of the oven was set to 100°C and maintained for a duration of one hour.
- As the oven temperature reached the desired level, the heating mechanism was deactivated, and an alarm signaled the completion of the heating process.
- Once the process was complete, the temperature was reset to its initial level, and the core samples were removed from the oven.
- Finally, the oven was switched off, concluding the moisture extraction process.

The core samples were allowed to remain in the oven for a period of one hour to ensure the extraction of the maximum amount of moisture. Following the extraction process, the samples were carefully transferred to a weight balance for subsequent measurement. The purpose of this measurement was to verify that the weight recorded before and after the moisture extraction process (referred to as weight 1 and weight 2, respectively) were equal. This step ensured the accuracy and effectiveness of the moisture extraction process.

The weight of the core samples before the interaction with the mud is presented in **Table 0-2**, while **Table 0-3** displays the weight of the core samples after the mud interaction.

Accurate measurement of the core sample weights before and after the moisture extraction process is crucial for assessing the effectiveness of the extraction and evaluating the impact of mud interaction on the samples. The recorded weights provide valuable data for analyzing the moisture content of the samples and understanding the extent of moisture removal achieved through the extraction process.

Sample #	Weight 1 (grams)
2b	70.52
3c	49.51
5c	54.62

Table 0-2 Core samples Weight before mud interaction and drying

The weight results show that the moisture from the core samples was very well extracted and that will lead us to the accurate results of permeability after interacting core samples with the mud.

Figure 0-1 Moisture Extraction Oven

Sample #	Weight 2 (grams)
2b	70.54
3c	49.52
5c	54.60

Table 0-3 Core samples Weight after mud interaction and drying

4.1.4. Permeability after Mud Interaction

Once the initial permeability of the core samples was determined, the next step involved immersing the core samples in mud. The mud used in this study was carefully prepared in the mud lab of the Petroleum Engineering department, with the aim of closely simulating industry practices.

The core samples were subjected to a 48-hour interaction period with the mud. This duration was chosen to assess the potential reduction in permeability caused by the mud and to examine the influence of the contamination time on the core samples.

Following the 48-hour interaction period with the mud, the core samples were carefully removed, cleaned, and subjected to a drying process in the Moisture Extraction Oven. This step aimed to achieve complete dryness in the cores for accurate weight measurements and to assess the effectiveness of the drying procedure.

To achieve the desired dryness, the core samples were exposed to a temperature of 120^0C for a duration of one hour. This controlled heating process allowed the moisture present in the cores to evaporate, ensuring that the samples reached a state of total dryness.

After the drying process, the core samples were weighed once again to compare the weight before mud interaction (weight 1) with the weight after mud interaction and drying (weight 2). The equality of these weights indicates the accuracy of the drying procedure and verifies that all moisture has been effectively extracted from the cores.

The comparison of weight measurements provides valuable insights into the extent of moisture content in the core samples before and after mud interaction. By ensuring that weight 1 matches weight 2, we can confidently conclude that the drying process successfully eliminated any residual moisture from the cores.

Table 0-4, presented below, displays the weight measurements obtained before mud interaction and after mud interaction and drying. These recorded values further contribute to the overall assessment of moisture extraction and provide a quantitative understanding of the effects of mud interaction on the core samples.

Sample #	Weight 1	Weight 2
2b	70.52	70.54
3C	49.51	49.50
5C	54.62	54.67

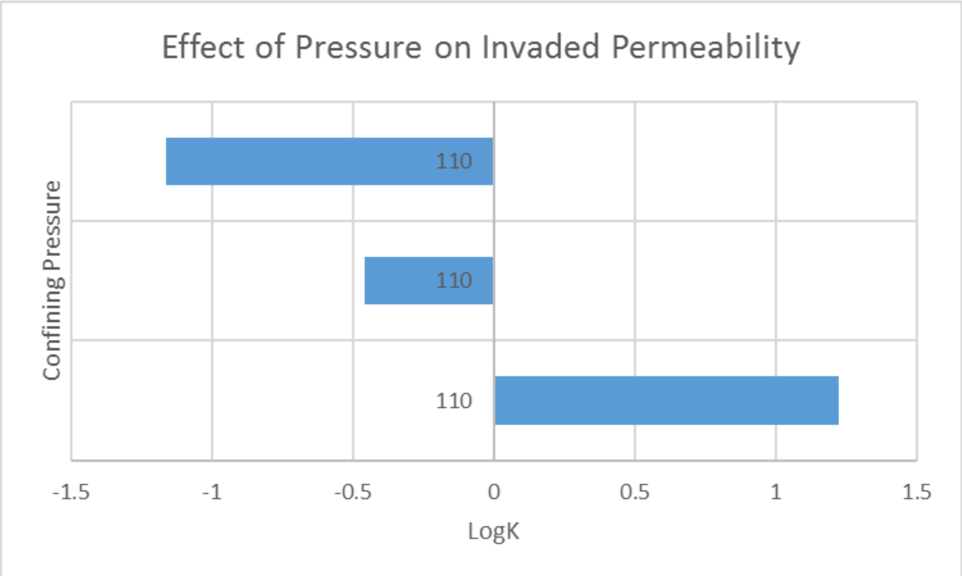
Table 0-4 Comparison of weight of core before and after mud interaction

It showed that the core samples were well dried and there was no any moisture left in the core samples.

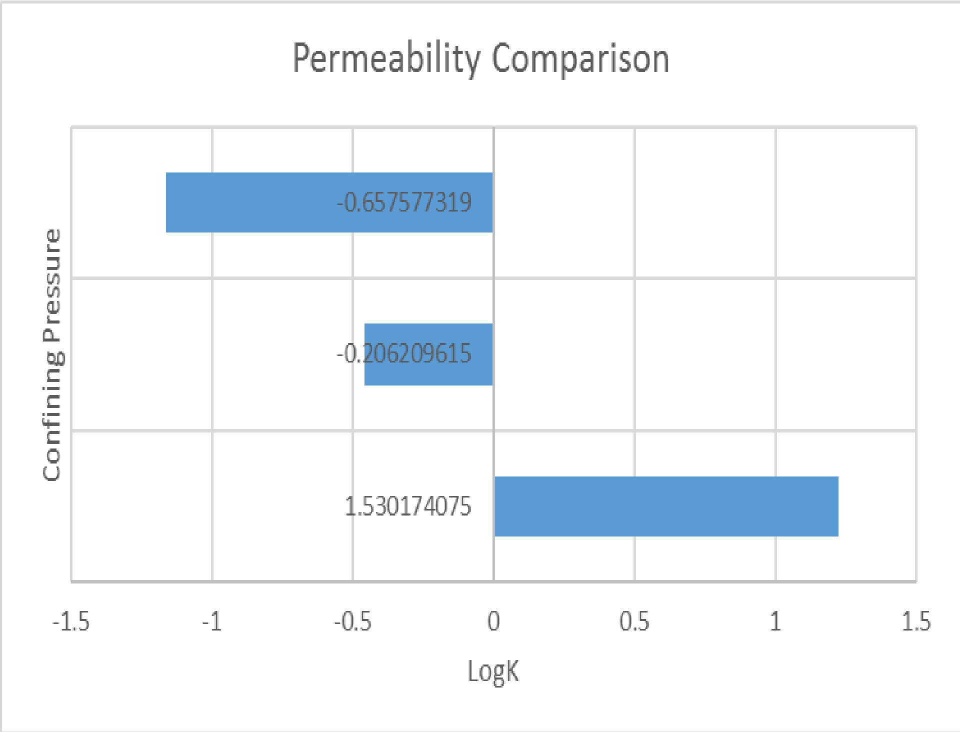
After this again permeability of the core samples was determined with gas permeability meter, the ***Table 0-5*** below shows the results obtained after the mud interaction with the core samples.

Sample #	∆P (diff pres)(psi)	P (upstream)(psi)	P (confining)(psi)	K (md)
2b	2.411	2.21	110	**0.069**
3C	2.137	2.09	110	**0.349**
5C	2.131	5.43	110	**16.679**

Table 0-5 Permeability of cores after mud interaction



As the Permeability values were small in range therefore Permeability values were taken with log in Excel to normalize the values to some extent.



4.2. Permeability Impairment:

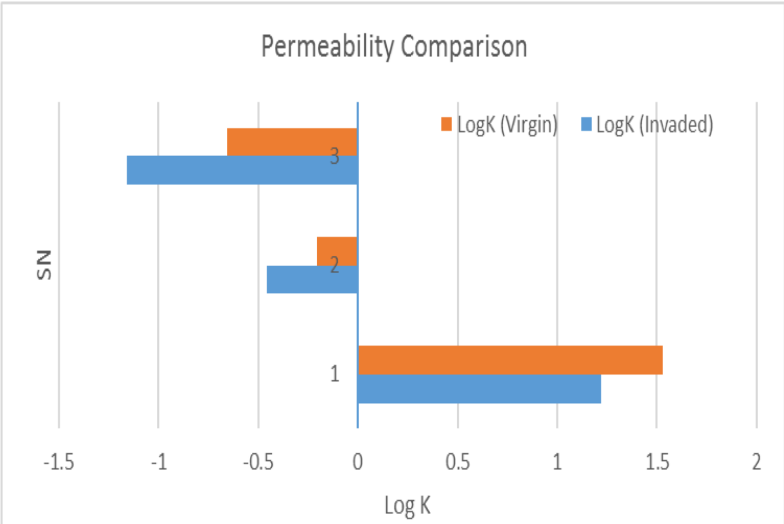
The obtained results clearly indicate a significant reduction in permeability as a result of the interaction between the core samples and the water-based mud. This reduction in permeability is attributed to the contamination time, which played a crucial role in the observed decrease.

The graph provided below illustrates a decreasing trend in permeability, reinforcing the impact of mud interaction on the core samples. One possible explanation for this trend is that upon introduction of the mud, solid particles present in the mud infiltrated deep within the pores of the core samples. These coarser solid particles penetrated the core samples, while the larger particles became lodged, leading to the blockage of pore throats. Consequently, during the drying process, these solid particles remained trapped, resulting in a reduction in permeability.

It is noteworthy that the decreasing trend in permeability is expected to continue as the contamination time increases. This emphasizes the progressive impact of prolonged exposure to the drilling fluid on permeability reduction. The longer the contamination time, the more pronounced the decrease in permeability becomes.

The observed reduction in permeability highlights the potential formation damage caused by the drilling fluid, particularly in terms of pore invasion and pore throat blockage. These findings align with the broader understanding that drilling fluid contamination can detrimentally affect the flow properties of reservoir rocks.

The chart below shows the initial permeabilities of the core samples and permeability after the mud interaction.



4.2.1. Invasion depth:

The discussion of the results emphasizes the significance of invasion depth as a critical parameter that should not be overlooked. It is evident that as the contamination time increases, the invasion depth becomes more pronounced. This can be attributed to the drilling fluid penetrating deeper into the core samples, leaving behind particles at greater depths, ultimately leading to an increase in skin formation.

The depth of invasion plays a crucial role in determining the extent of contact between the filtrate or drilling fluid and the sensitive clay present within the core samples. The deeper the penetration of the fluid, the higher the likelihood of interaction with the sensitive clay. This interaction can have significant implications for the well's economics and overall performance.

Understanding the invasion process and its relationship with the economic aspects of the well is vital. The invasion depth directly impacts the formation damage and subsequent permeability reduction observed in the core samples. By comprehending this relationship, petroleum engineers and companies can make informed decisions regarding drilling fluid selection, mud properties, and mitigation strategies to minimize invasion and formation damage.

Considering the economic implications, it is crucial to strike a balance between effective drilling operations and the potential risks associated with invasion and formation damage. By optimizing drilling practices and implementing preventive measures, it becomes possible to minimize the economic impact of invasion and maximize the productivity and longevity of the well.

4.2.2. Contamination time:

Skin increases with the increase in the contamination time. The relation of invasion depth and skin is directly proportional that can be described as:

Skin = (0.1125 × contamination time) – 0.8062

4.3. Formation impairment: vertical vs Horizontal wells

The discussion of results highlights the significant impact of formation damage in horizontal wells compared to vertical wells. Horizontal wells, with their longer wellbore sections, are more susceptible to near-wellbore damage due to increased contact area and extended contamination time with drilling and completion fluids. Several factors contribute to the quantification of damage in horizontal and vertical wells, as outlined below:

- Time of drilling: The drilling of a horizontal section takes longer compared to a vertical well. This increased drilling time results in a prolonged contact or contamination time between the drilling and completion fluid and the pay zone. The extended period of contact increases the potential for formation damage, leading to the development of skin in horizontal wells.
- Open hole completion: Horizontal wells often employ open hole completion methods, which can contribute to shallow damage. Shallow damage is typically addressed through perforating charges in cased completions, which are not applicable in open hole completions. This distinction further accentuates the potential for formation damage in horizontal wells.

- Flow dynamics: Horizontal wells have a larger area exposed to fluid flow compared to vertical wells. Consequently, when both vertical and horizontal wells are flowing at the same rate, the fluid velocity in horizontal wells is significantly lower due to the increased flow area. During backflow operations, the lower pressure gradient and fluid velocity in horizontal wells may hinder the efficient removal of the mud cake. This limited efficiency raises questions about the productivity and performance of horizontal wells.

In cased completions of vertical wells, less acid is required to remove formation damage, and the diversion of acid to specific sections or layers is relatively straightforward. In contrast, horizontal wells demand larger volumes of acid, accompanied by technical complexities regarding the precise placement of the acid at specific locations in the wellbore. These challenges impact the proper placement of acid, the expected outcomes of acidizing treatments, and the economic viability of such interventions in horizontal wells.

Understanding the distinct challenges and factors influencing formation damage in horizontal wells is crucial for optimizing drilling and completion practices, as well as designing effective remedial measures. By addressing the specific needs and risks associated with horizontal wells, the industry can enhance well performance, minimize formation damage, and maximize economic returns.

4.4. Conclusion and recommendation

The study aimed to investigate the impact of drilling fluids and mud contamination time on formation permeability and the resulting impairment during drilling operations. Experimental tests were conducted under a confining pressure of 110-psi, which revealed a noticeable impairment in permeability.

Based on the findings, it can be concluded that the skin factor, which represents formation damage, increases with higher overbalance pressure. The presence of solid particles stuck in pore throats intensifies the invasion depth as the overbalance pressure rises. Additionally, contamination time has a significant effect on invasion depth. Both increasing overbalance pressure and longer contamination time contribute to reduced permeability regain.

Furthermore, the penetration of mud is influenced by contamination time. The longer the contamination time, the deeper the mud can infiltrate the formation. This emphasizes the detrimental impact of drilling-induced formation damage, particularly in horizontal wells.

In light of the experimental findings and the study's conclusion, several recommendations can be made to mitigate formation damage and maximize production:

- Minimize overbalance pressure and contamination time: It is crucial to keep both overbalance pressure and contamination time as low as possible. This helps to stay within the safe operating window and reduces the risk of formation damage. Implementing proper wellbore cleaning practices and optimizing drilling parameters can aid in achieving this objective.
- Optimize mud design: Developing a well-designed mud system with minimal solid particles is highly recommended. Careful selection of mud additives and effective fluid rheology management can contribute to reducing formation damage. This recommendation is applicable to both vertical and horizontal wells, but its significance is amplified in horizontal wells where the potential for damage is higher.
- Further experiments and acidizing job: Expanding the scope of experiments by testing different drilling fluids and conducting acidizing jobs on limestone formations can provide valuable insights. Measuring the regain in permeability after acidizing will help determine the most effective acidizing practices and identify the acid or fluid that yields the maximum permeability regain. This information can guide future acidizing operations and optimize formation productivity.
- Consideration of different acids/fluids: It is recommended to perform acidizing experiments using various acids or fluids to assess their effectiveness in enhancing permeability regain. By comparing the results, the best acid or fluid for achieving maximum permeability improvement can be identified. This knowledge will contribute to informed decision-making during acidizing treatments.

These recommendations aim to minimize formation damage, optimize production, and maximize the benefits of horizontal well operations. Further research and experimentation in these areas will help refine drilling practices, enhance well performance, and improve the economics of oil and gas operations.

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